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REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JAOQUIN BASIN, CALIFORNIA

Annual Report
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By
Steve Schamel

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Energy & Geoscience Institute at the
University of Utah
Salt Lake City, Utah

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Tulsa, Oklahoma

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Reactivation of an Idle Lease to Increase Heavy Oil Recovery through Application of Conventional Steam Drive Technology in a Low Dip Slope and Basin Reservoir in the Midway-Sunset Field, San Jaoquin Basin, California

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

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National Petroleum Technology Office
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Abstract

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This project reactivates ARCO's idle Pru Fee lease in the Midway-Sunset field, California and conducts a continuous steamflood enhanced oil recovery demonstration aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming was used to reestablish baseline production within the *reservoir characterization phase* of the project completed in December 1996. During the *demonstration phase* begun in January 1997, a continuous steamflood enhanced oil recovery is testing the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs having similar producibility problems will benefit from insight gained in this project. The objectives of the project are: (1) to return the shut-in portion of the reservoir to optimal commercial production; (2) to accurately describe the reservoir and recovery process; and (3) to convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

Executive Summary

REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JAOQUIN BASIN, CALIFORNIA

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Objective

This project reactivates ARCO's idle Pru Fee lease in the Midway-Sunset field, California and conducts a continuous steamflood enhanced oil recovery demonstration aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming is being used to reestablish baseline production within the *reservoir characterization phase* of the project. During the *demonstration phase* begun in January 1997, a continuous steamflood enhanced oil recovery was initiated to test the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs having similar producibility problems will benefit from insight gained in this project. The objectives of the project are: (1) to return the shut-in portion of the reservoir to optimal commercial production; (2) to accurately describe the reservoir and recovery process; and (3) to convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

The 40 ac Pru Fee property is located in the super-giant Midway-Sunset field (Figure 1.1) and produces from the late Miocene Monarch Sand, part of the Monterey Formation. The Midway-Sunset Field was drilled prior to 1890. In 1991 cumulative production from the field reached two billion barrels, with remaining reserves estimated to exceed 695 MMBO. In the Pru Fee property, now held by ARCO Western Energy, cyclic steaming was used to produce 13° API oil. However, the previous operator was unable to develop profitably this marginal portion of the Midway-Sunset field using standard enhanced oil recovery technologies and chose rather to leave more than 3.0 MMBO of oil in the ground that otherwise might have been produced from the 40 ac property. Only 927 MBO had been produced from the property when it was shut-in in 1987. This is less than 15% of the original oil-in-place, which is insignificant, compared to typical heavy oil recoveries in the Midway-Sunset field of 40 to 70%. Target additional recoverable oil reserves from the 40 ac property are 2.9 MMBO or greater. The objective of the demonstration project is to encourage a similar incremental increase in production in all other marginal properties in the Midway-Sunset and adjacent fields in the southern San Joaquin Basin.

A previously idle portion of the Midway-Sunset field, the ARCO Western Energy Pru Fee property, is being brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the Monarch Sand. However, the sand lacks effective steam barriers and has a thick water-saturation zone above the oil-water contact. These factors require an innovative approach to steam flood production design that will balance optimal total oil production against economically viable steam-oil ratios and production rates. The methods used in the Class III demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize declining production of heavy oils throughout the region.

Significant Project Results in Year 3

Activities on the pilot site during the preparation of the steam flood demonstration included drilling 18 new wells - 11 producers (Pru-201 through Pru-211), 4 injectors (Pru 12-1 through Pru 12-4), and three temperature observation wells (TO-2 through TO-4). The drilling was started on January 14 and completed on March 16, 1997. All wells were logged. The four pattern, 9-spot array utilizes 10 pre-existing wells that were recompleted and cyclic steamed in the initial phase of the project. All new wells were drilled into the oil-water contact to establish the depth of that horizon. The producers were completed through the entire pay zone, however, the injectors were completed so as to maintain the critical standoff from the OWC deemed optimal in earlier simulations. On the basis of the new wells, the stratigraphic model for the pilot was reevaluated on using GeoGraphix (GES and Prizm) workstation software and the geostatistical distribution of porosity and permeability rerun using GeoMath's Heresim package. This analysis preceded revision of the thermal simulator for the pilot. History matching of steam injection rates and monthly production to fine tune the simulator will provide the basis for optimization of production practices and parameters for the next several years of the demonstration.

By mid-April 1997 all of the producers had been primed and all of the facilities were in place to begin injection within the four-fold, nine-spot array of the Pru pilot. At the end of April injection began with a target rate of 300 barrels of steam per day (bspd) for each of the four injectors. In actuality, the rates have been in the range 250 to 300 bspd. In three of the injectors the initial injection pressure was about 600 psi, dropping gradually over a 6 to 8 week period to a relatively stable 300-350 psi. However, in Pru I2-2, the initial injection pressure of 500 psi dropped very quickly to plateau at 300-350 psi.

Four temperature observation (TO) wells monitor the buildup of heat within the Monarch Sand reservoir. The temperatures observed in the TO wells most closely reflect their proximity to the injection wells at the level of the top of the reservoir:

TO-1	80 feet from I2-2
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Already by the end of June 1997 an increase in temperature was noted in all of the TO wells, but most pronounced in TO-3. Temperatures had reached a plateau in TO-3 by the end of 1997, but were still increasing in TO-1 and TO-4 through the second quarter of 1998.

The average temperature of produced oil from the steam flood pilot also is indicating the buildup of heat in the reservoir. In April 1997, just as the steam flood began the average produced oil temperature was 102° F. Two months later, in June 1997 the average temperature had increased to 125.6° F; by August 1997 it was 136.6° F. In the first quarter of 1998 the temperature stalled around 144-145°. Since then the temperature has continued to climb to 154° F, a temperature at which the Pru oil has a viscosity of about 100-150 centipoise and is easily pumped.

During the initial cyclic baseline test period in 1996, production averaged for the total group of 9 wells about 65 BOPD, ranging from 3 to 10 BOPD/well for the old wells and about 15 BOPD for the new Pru 101 well. Total production during the cyclic baseline testing was 28.7 MBO. As soon as the group of new producers had been primed by steaming and in turn put into production in the early summer 1997, rates for the pilot climbed to over 400 BOPD. The sharp increase in production can, in part, be attributed to the increase in the number of producers from 9 to 20 and the fact that the performance of the new wells is consistently better than the old renovated wells. However, the well average jumped from about 8 BOPD to nearly 20 BOPD with the onset of the pilot steam flood. As of March 1998, the rate at the Pru pilot was averaging 420 BOPD. However, in the second quarter of 1998, oil production declined somewhat reaching a monthly average of just 299.4 BOPD in May before climbing back up to 345.2 BOPD in June. The cumulative production of the Pru pilot (June 1998) at this early stage of buildup of the steam chest in the reservoir is 180.0 MBO, which exceeds projections based on the current thermal simulator. Temperature monitoring at the site is suggesting that full steam flood production had begun late in 1997.

Oil production at this early stage of the Pru steam flood demonstration is nearly an order of magnitude greater than the average monthly production during the previous "cyclic baseline" testing.

Chapter 1

Introduction

Objective

This project reactivates ARCO's idle Pru Fee lease in the Midway-Sunset field, California and conducts a continuous steamflood enhanced oil recovery demonstration aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming is being used to reestablish baseline production within the *reservoir characterization phase* of the project. During the *demonstration phase* begun in January 1997, a continuous steamflood enhanced oil recovery was initiated to test the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs having similar producibility problems will benefit from insight gained in this project. The objectives of the project are: (1) to return the shut-in portion of the reservoir to optimal commercial production; (2) to accurately describe the reservoir and recovery process; and (3) to convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

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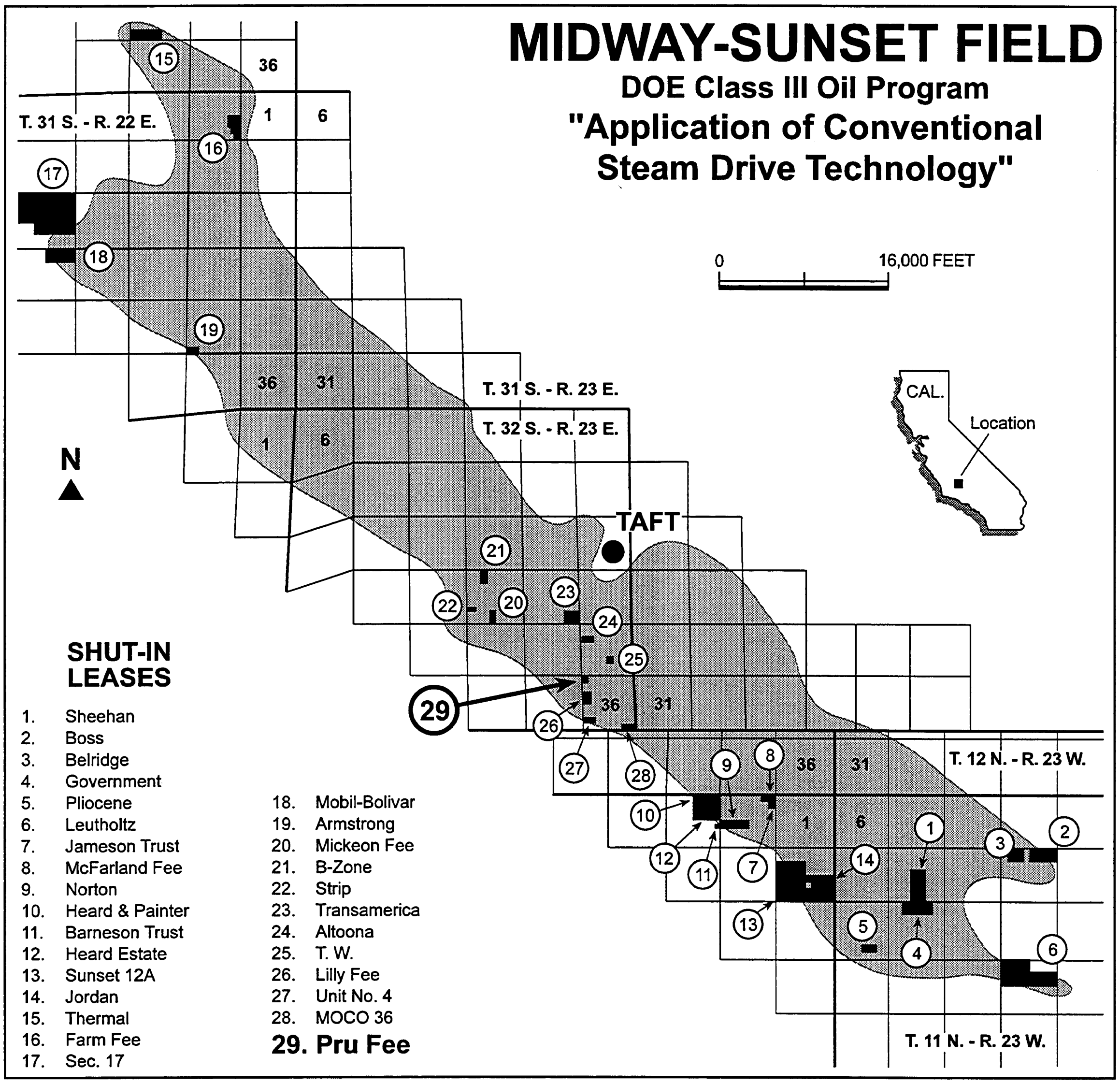

Figure 1.1: Index map of the Midway-Sunset field showing location of the Pru Fee property and other shut-in leases.

Project Organization

This Class III Oil Technology Demonstration, which is sponsored with matching funds from the U.S. Department of Energy, Office of Fossil Fuels, involves the collaboration of three separate organizations:

- the *University of Utah*, represented by the Energy & Geoscience Institute, serving as the Prime Contractor and project coordinator
- *ARCO Western Energy*, the owner and operator of the Pru Fee property

- the *Utah Geological Survey*, responsible for technology transfer and geologic evaluation.

The project team members and their particular areas of responsibility to the project are:

Energy & Geoscience Institute at the University of Utah (Salt Lake City, UT)
- Dr. Steven Schamel - project manager and research coordinator
- Dr. Craig Forster - reservoir characterization and geostatistics

Department of Chemical and Fuels Engineering, University of Utah
- Dr. Milind Deo - reservoir characterization and simulation
- Ms. Hongmei Huang - geostatistics and reservoir simulation

ARCO Western Energy (Bakersfield, CA)
- Mr. Kevin Olsen- petroleum engineering and site management
- Mr. Mike Simmons - petroleum geology and reservoir characterization

Utah Geological Survey (Salt Lake City, UT)
- Dr. Doug Sprinkel - stratigraphic analysis and reservoir characterization
- Dr. Roger Bon - technology transfer

ARCO Exploration and Production Technology (Plano, TX)
- Dr. Creties Jenkins - advisor for stratigraphy and reservoir characterization

Authors of this annual report are: Steven Schamel (Chapter 2), Doug Sprinkel (Chapter 3), Craig Forster (Chapter 4), Milind Deo (Chapter 5), Steven Schamel (Chapters 6). The report was edited and assembled by Steven Schamel.

Project Activities in Year 3

The steam flood pilot was initiated in the first half of 1997 and was well underway during the start of year 3. A variety of activities have been carried out during the period July 1997 through June 1998. This period essentially was one of the initial production and data collection to monitor the early response of the Monarch Sand reservoir to this mode of enhanced oil recovery.

The principal activities during the year included:

- Steam flood and production surveillance
- Completion of the stratigraphic characterization of the pilot site based on the new suite of electronic logs
- Geostatistical characterization of the pilot site to examine the spatial distribution of petrophysical properties and water saturations.
- Additional studies based on the reservoir simulator.

Chapter 2

Initial Results of the Steam Flood Pilot

Activities on the pilot site during the preparation of the steam flood demonstration included drilling 18 new wells - 11 producers (Pru-201 through Pru-211), 4 injectors (Pru 12-1 through Pru 12-4), and three temperature observation wells (TO-2 through TO-4). The drilling was started on January 14 and completed on March 16, 1997. All wells were logged. The four pattern, 9-spot array (Figure 1) utilizes 10 pre-existing wells that were recompleted and cyclic steamed in the initial phase of the project. All new wells were drilled into the oil-water contact to establish the depth of that horizon. The producers were completed through the entire pay zone, however, the injectors were completed so as to maintain the critical standoff from the OWC deemed optimal in earlier simulations. On the basis of the new wells, the stratigraphic model for the pilot was reevaluated on using GeoGraphix (GES and Prizm) workstation software and the geostatistical distribution of porosity and permeability rerun using GeoMath's Heresim package. This analysis preceded revision of the thermal simulator for the pilot. History matching of steam injection rates and monthly production to fine tune the simulator will provide the basis for optimization of production practices and parameters for the next several years of the demonstration.

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Heating the Monarch Sand Reservoir

Four temperature observation (TO) wells (Figure 2-1) monitor the buildup of heat within the Monarch Sand reservoir. The temperatures observed in the TO wells most closely reflect their proximity to the injection wells at the level of the top of the reservoir:

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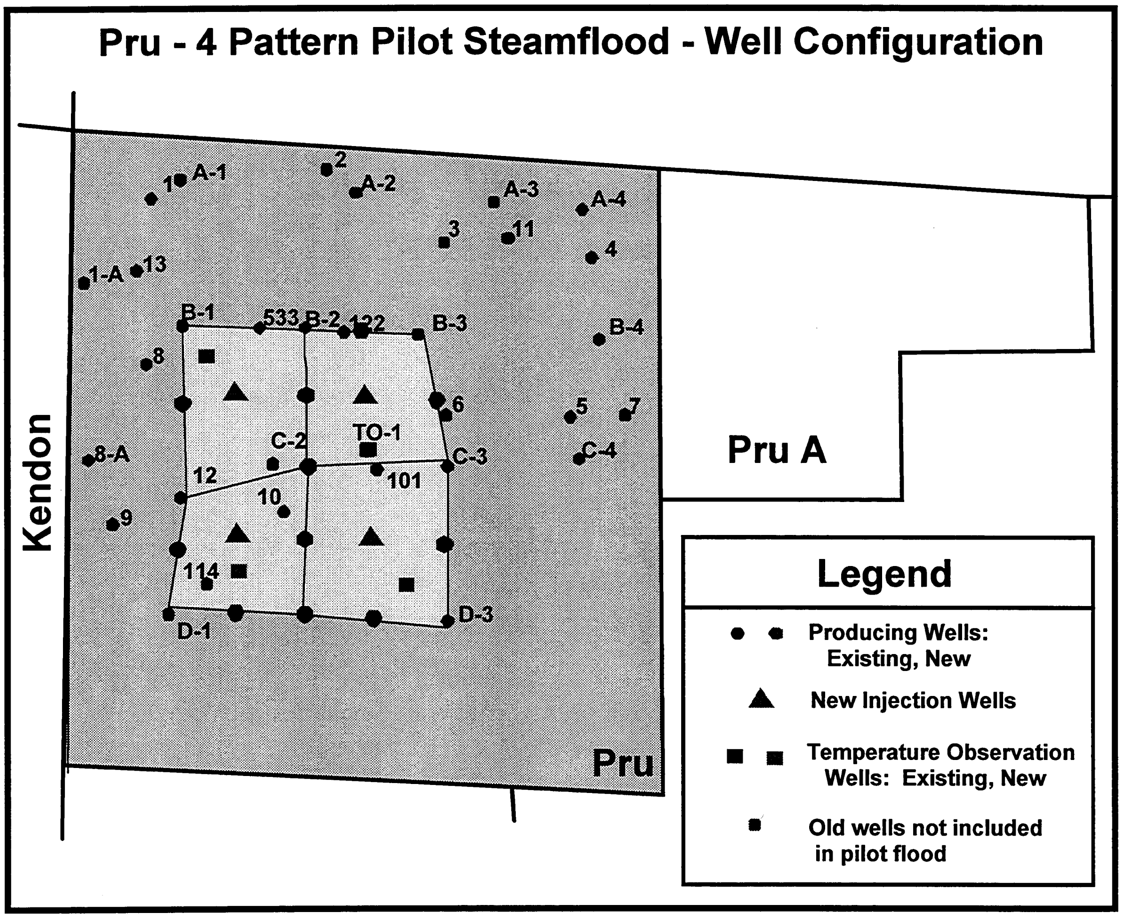

Figure 1: Map of the Pru steam flood well array. The four injectors are shown as triangles, the four TO wells as squares and the 20 producers as circles. Location of temperature observation wells: TO-1 in NE quadrant, TO-2 in NW quadrant, TO-3 in SW quadrant, and TO-4 in SE quadrant.

Well TO-2, which is 120 ft from the nearest injector, exhibited very little increase in temperature since the onset of the steam flood.

The buildup of heat in the Monarch Sand reservoir since the start of the steam flood, as monitored at the temperature observation wells, is shown graphically in Figures 2-2 through 2-5. Note the very rapid rise of temperature in TO-3 along two stratigraphic intervals, followed by a small decline as the heat dissipates through the adjacent portions of the reservoir. The two wells TO-1 and TO-4 exhibit a more gradual increase in temperature and relatively narrow temperature spikes. TO-4 has a small secondary temperature spike at the top of the Monarch Sand. The double spike probably is controlled by the presence at this location of a thin tapered layer of Belridge diatomite between the Monarch Sand and the base-Etchegoin unconformity.

A striking feature of all curves is how high the temperature peaks are within the Monarch Sand reservoir. All are near the very top of the reservoir; some extend over into the base of the Etchegoin Formation. This unit rests unconformably on the Monarch Sand at Pru and is considered to be the top-seal. Apparently, some of the heat is escaping, either by steam migration or conduction, into the lower portion of this Pliocene silt, lime and shale-rich non-marine formation.

The average temperature of produced oil (Figure 2-6) from the steam flood pilot also is indicating the buildup of heat in the reservoir. In April 1997, just as the steam flood began the average produced oil temperature was 102° F. Two months later, in June 1997 the average temperature had increased to 125.6° F; by August 1997 it was 136.6° F. In the first quarter of 1998 the temperature stalled around 144-145°. Since then the temperature has continued to climb to 154° F, a temperature at which the Pru oil has a viscosity of about 100-150 centipoise and is easily pumped.

Current Production in Pru Steam Flood Demonstration

During the initial cyclic baseline test period in 1996, production averaged for the total group of 9 wells about 65 BOPD, ranging from 3 to 10 BOPD/well for the old wells and about 15 BOPD for the new Pru 101 well. Total production during the cyclic baseline testing was 28.7 MBO. As soon as the group of new producers had been primed by steaming and in turn put into production in the early summer 1997, rates for the pilot climbed to over 400 BOPD. The sharp increase in production can, in part, be attributed to the increase in the number of producers from 9 to 20 and the fact that the performance of the new wells is consistently better than the old renovated wells. However, the well average jumped from about 8 BOPD to nearly 20 BOPD with the onset of the pilot steam flood. As of March 1998, the rate at the Pru pilot was averaging 420 BOPD. However, in the second quarter of 1998, oil production declined somewhat reaching a monthly average of just 299.4 BOPD in May before climbing back up to 345.2 BOPD in June. The cumulative production of the Pru pilot (June 1998) at this early stage of buildup of the steam chest in the reservoir is 180.0 MBO, which exceeds projections based on the current thermal simulator. Refer to Table 2-1 and Figure 2-6. Temperature monitoring at the site is suggesting that full steam flood production had begun late in 1997.

Oil production at this early stage of the Pru steam flood demonstration is nearly an order of magnitude greater than the average monthly production during the previous "cyclic baseline" testing.

Table 2-1: Monthly Average Production at the Pru Steam Flood Pilot
June 1997-June 1998

Month	BOPD	BWPD	BSPD	CumOil	CumWater
June	380.4	1,473.8	1,331.8	48,917.0	306,823.0
July	424.4	1,559.0	1,033.3	62,073.0	355,153.0
August	349.0	1,686.0	1,114.7	72,891.0	407,419.0
September	303.9	1,563.0	1,548.9	82,008.0	454,308.0
October	329.7	1,637.8	1,912.5	92,228.0	505,080.0
November	366.6	1,602.4	1,642.3	103,225.0	553,151.0
December	380.7	1,835.3	1,064.7	115,027.0	610,045.0
January	352.4	1,635.6	1,057.0	125,952.0	660,750.0
February	410.6	1,842.8	1,002.4	137,448.0	712,349.0
March	419.0	1,776.6	1,108.8	150,436.0	767,423.0
April	332.5	1,681.4	1,790.9	160,412.0	817,864.0
May	299.4	1,869.0	2,047.7	169,692.0	875,804.0
June	345.2	1,689.1	1,130.5	180,047.0	926,476.0

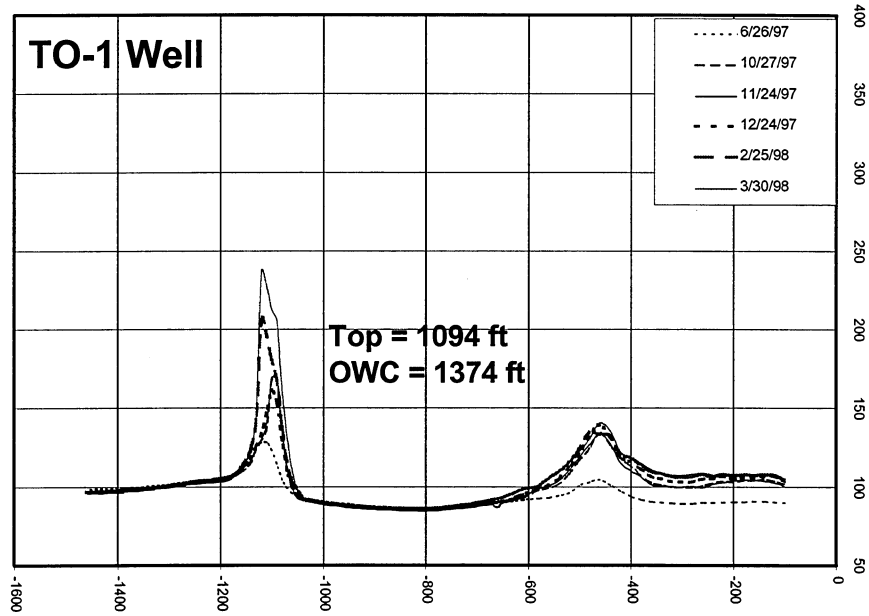

Figure 2-2: Plot of temperature logs for the TO-1 well in the NE quadrant of the Pru steam flood pilot for the period June 1997 through March 1998.

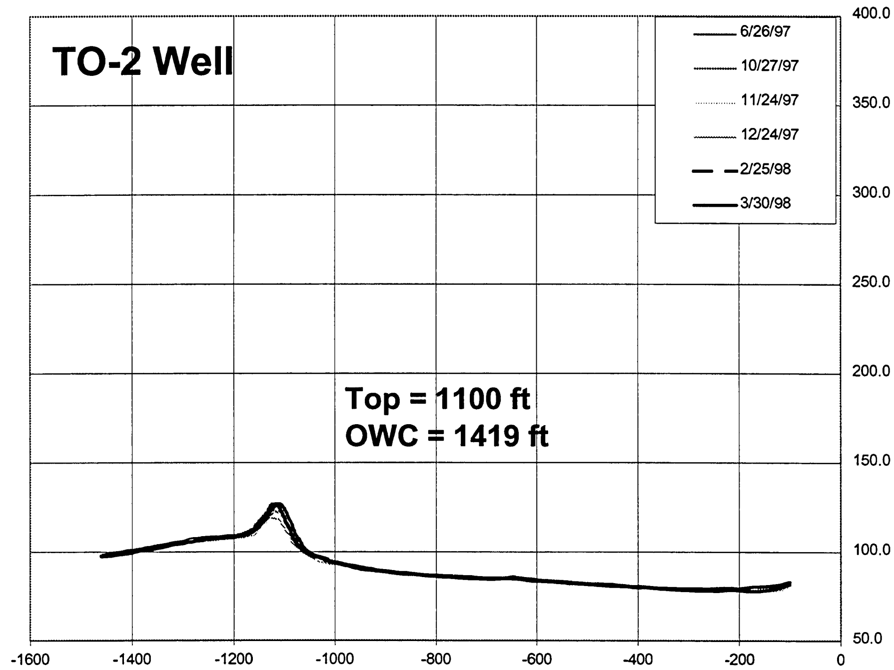

Figure 2-3: Plot of temperature logs for the TO-2 well in the NW quadrant of the Pru steam flood pilot for the period June 1997 through March 1998.

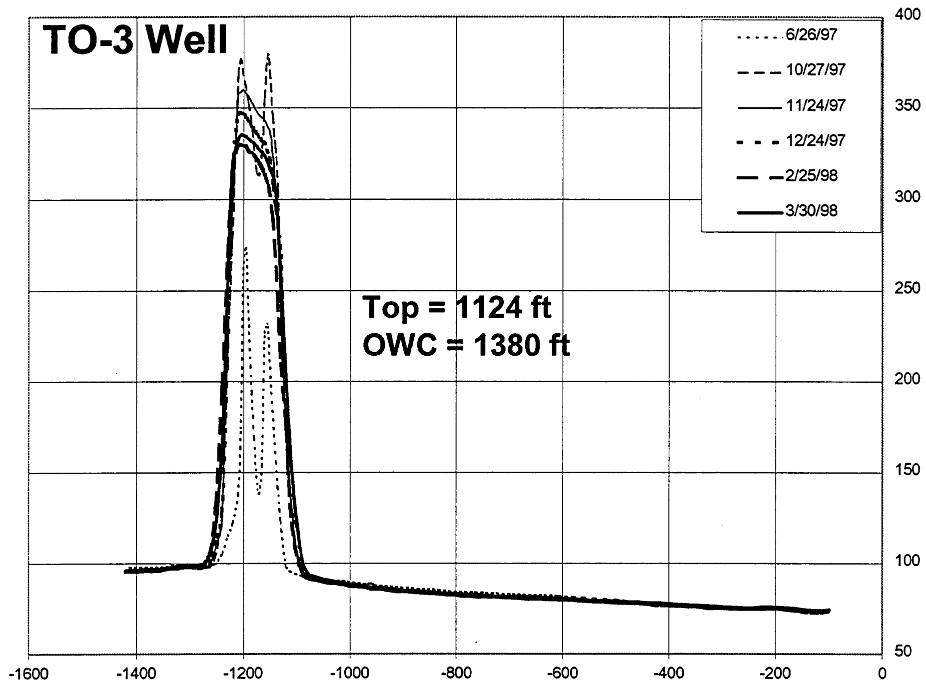

Figure 2-4: Plot of temperature logs for the TO-3 well in the SW quadrant of the Pru steam flood pilot for the period June 1997 through March 1998.

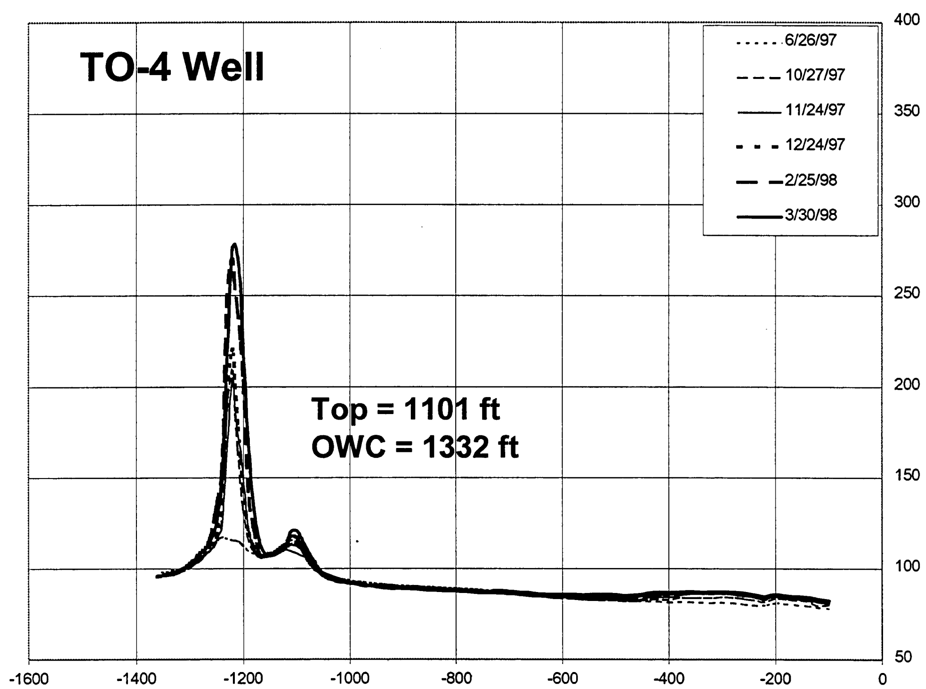

Figure 2-5: Plot of temperature logs for the TO-4 well in the SE quadrant of the Pru steam flood pilot for the period June 1997 through March 1998.

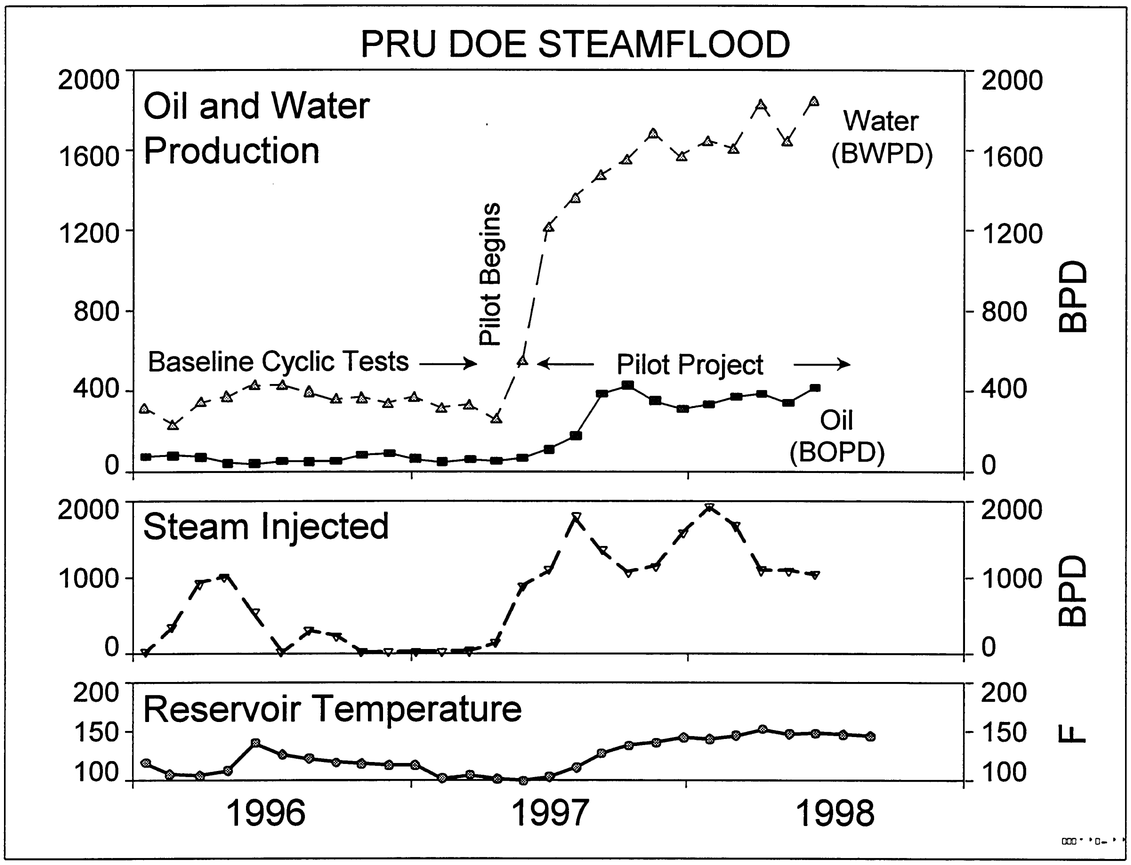

Figure 2-6: Plot of fluids produced, steam injected and temperature of produced fluids through the life of the Pru Class 3 oil technology demonstration.

Chapter 3

Stratigraphic Characterization

General Statement

The Midway-Sunset field produces oil from multiple reservoirs that range in age from Oligocene to Pleistocene. However, most of the production is from the Upper Miocene sand reservoirs (Hall and Link, 1990). Production at the ARCO Western Energy (AWE) Pru Fee property is from the Upper Miocene Monarch sand. At the 8 ac Pru pilot demonstration site, in the center of the Pru Fee property (Fig. 3-1), the average depth to the Monarch sand is 1,099 feet (Table 3-1).

The stratigraphic nomenclature applied to this part of the Midway-Sunset field is a combination of formal units (which are recognized at the surface and in the subsurface) and informal units, which are mostly identified in the subsurface. The stratigraphic nomenclature of Foss and Blaisdell (1968), Reid (1990), Nilsen (1996), and Sturm (1996) has been adopted in for this project as it most closely reflects that used by the petroleum industry.

The Monarch sand is one of several sand lenses within the Belridge Diatomite Member of the Monterey Formation (Fig. 3-2). It overlies the informal Republic, Williams, and Leutholtz sands (in descending order) of the Antelope Shale. The Reef Ridge Shale overlies the Monarch in other portions of the Midway-Sunset field. However, a regional Pliocene unconformity, referred to as the sub-Etchegoin unconformity (Sturm, 1996), truncates the Reef Ridge Shale and the top of the Belridge Diatomite Member at the Pru site. Here the Pliocene Etchegoin Formation rests with a low angle unconformity on the Monarch sand and an overlying Belridge Diatomite Member mudstone unit. The base of the Monarch Sand lens has not been penetrated at the Pru site. Its total thickness and relationship to underlying mudstones in the Belridge Diatomite Member are not known. However, the Monarch Sand is known to be at least 320 ft thick at the TO-2 well.

Stratigraphic Modeling of the Monarch Sand

The Monarch Sand at the Pru pilot site has been characterized using petrophysical logs from the 18 new wells drilled in January-March, 1997 and petrophysical logs, core descriptions, and petrophysical data from 3 older wells (Pru 101, Pru TO-1, and Pru 533) (Fig. 3-1). The two wells in the Pru property with nearly continuous core through the Monarch Sand, Pru 101 and Pru 533, provided the basis for calibrating log response with lithology and petrophysical properties (Fig. 3-3) and for testing the validity of log-based bed-scale stratigraphic correlation.

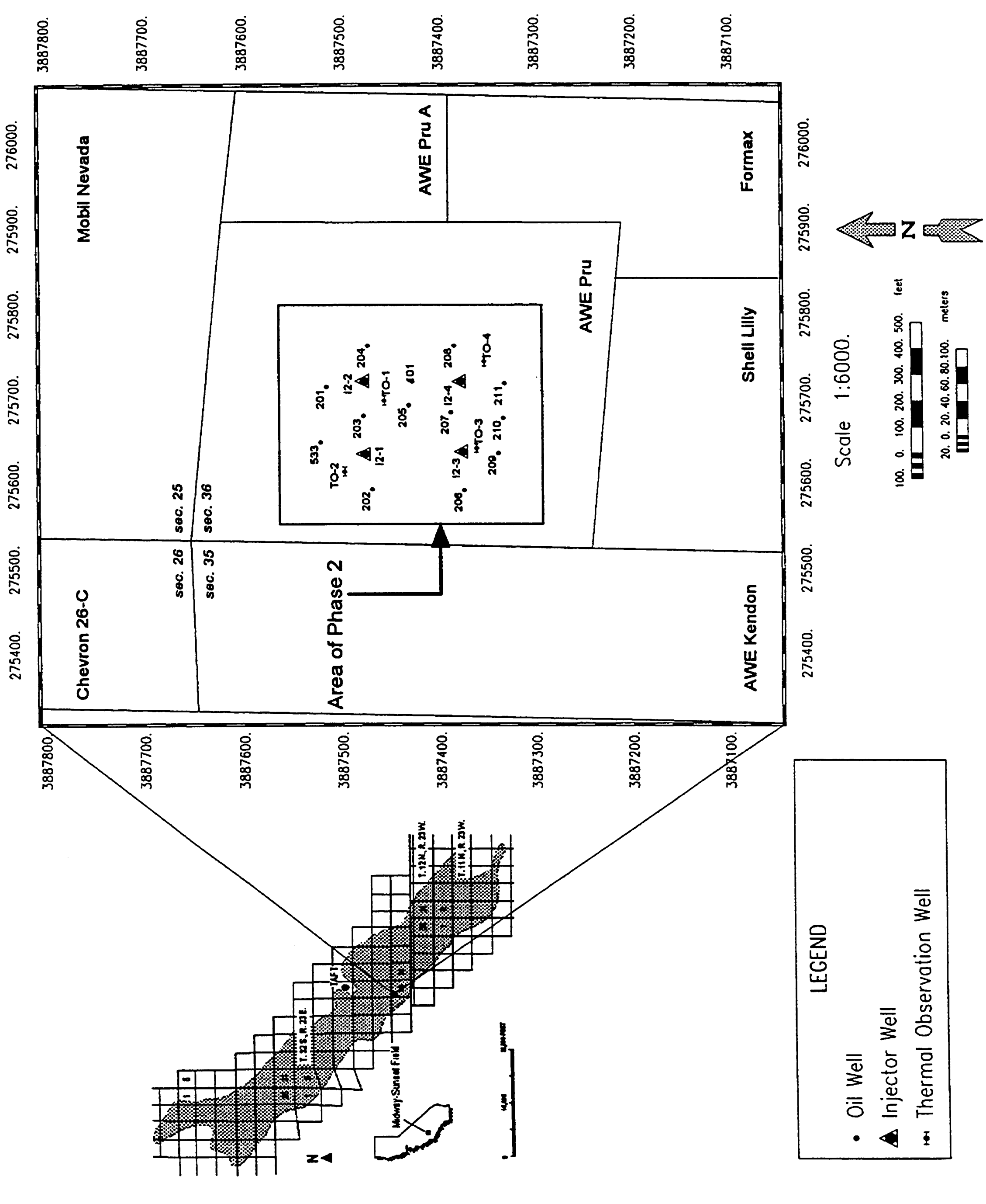

Figure 1. The Pru project encompasses the AWE Pru and adjacent leases. Wells used for the stratigraphic characterization in Phase 2 are within the AWE Pru lease. Map coordinates are in UTMs, zone 11.

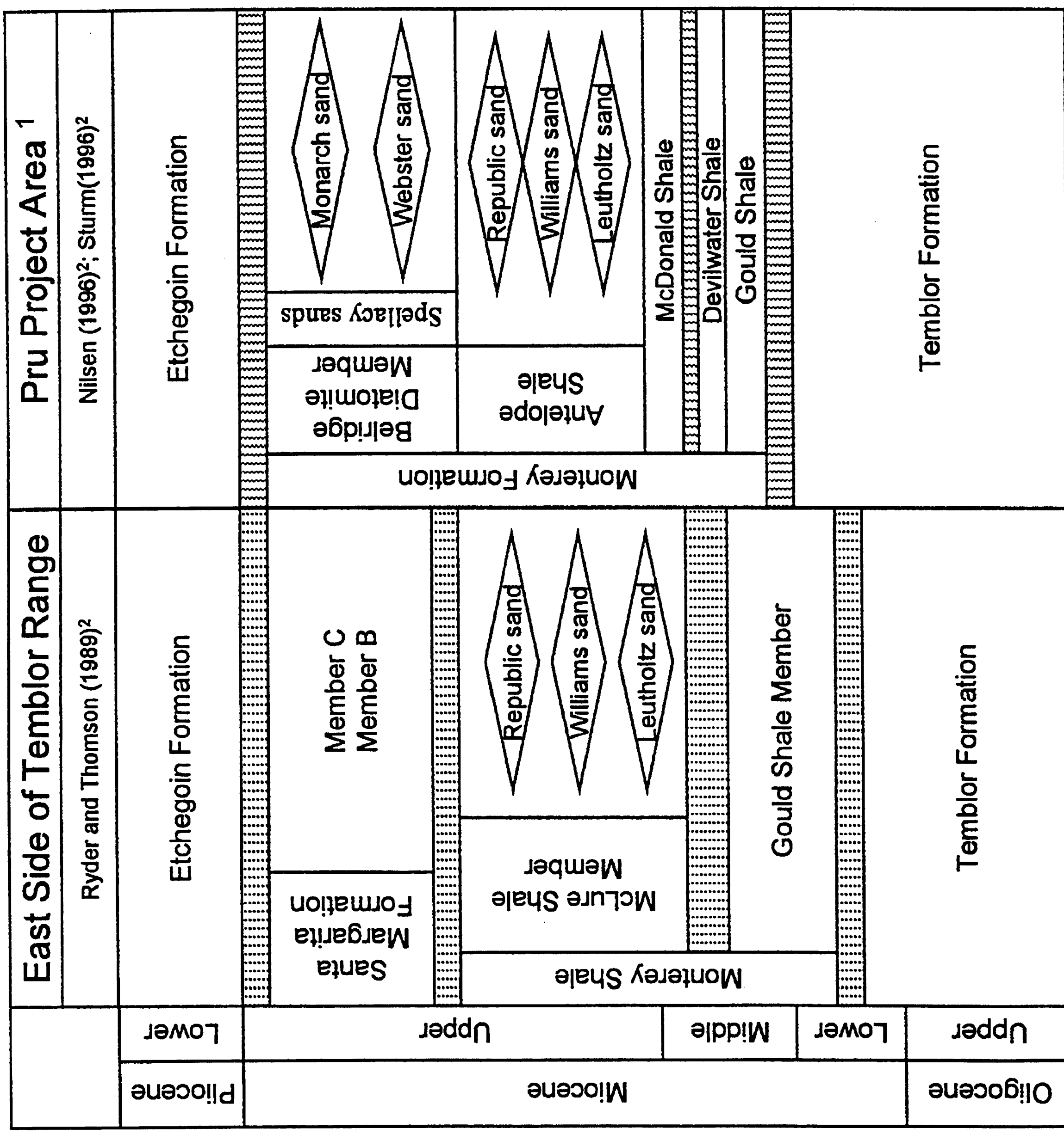

Figure 2. Stratigraphic table of formations in the Pru project area and east side of the Temblor Range. ¹ The Monarch sand is the oldest formation penetrated in the Pru project area. ² Modified for the Pru project area

The Monarch Sand is relatively homogeneous and is dominated by thin-bedded, poorly to very poorly sorted, medium- to coarse-grained sandstone. Characteristically, medium-grained sand, coarse-grained sand, granule sand, and pebble sand form graded beds and sand-on-sand bed successions one to several ft in thickness. The sand packages periodically are punctuated by diatomaceous mudstone and muddy bioturbated fine-grained sand. Cobble-size clasts (granite, gneiss and schist) up to 18 in diameter are observed in core and noted in logs by a high gamma spikes associated with abnormally low log porosity values. The overall lithological characteristics of the Monarch Sand are those of a proximal turbidite as described by Bouma (1962), Mutti and Ricci-Lucchi (1972; 1975), Walker and Mutti (1973), and Bouma et al. (1985). The stacking patterns, coarsening upward grain size, and a general coarse-grained nature of the highly graded beds can be interpreted as a progradational turbidite sequence (Walker, 1981). Refer to the 1995-96 annual report for a detailed description by Creties Jenkins of the Pru 101 core and lithofacies within the Monarch Sand.

In general, the sandy lithofacies present within the Monarch Sand alternate at a scale of a few feet or less and exhibit similar electrical log responses. This makes it virtually impossible to reliably distinguish a poorly sorted medium-grain sand from a course-grain sand. Only the two extreme lithofacies, diatomaceous mudstone and the pebbly sand, can be interpreted with any confidence from the logs. Both of these lithofacies are characterized by high gamma log values. In addition, they exhibit the two extremes in density porosity. The mudstone lithofacies consistently is associated with log porosity values greater than 35 %, whereas pebbly sand lithofacies generally has log porosity values less than 26 %. In the wells for which core is not available, these two lithofacies are determined from a combination density porosity and gamma ray logs. All other intervals are merely the "sand" lithofacies undivided. Even though the wells are very closely spaced and the log suites are comparable, only the mudstone lithofacies could be correlated with any degree of reliability. The pebbly sand lithofacies is either too limited in lateral extent or too variable in log properties to be correlated as discrete layers. Only broadly delimited intervals in which this lithofacies was present could be carried through a few adjacent wells.

The mudstone lithofacies, significant as a potential barrier or baffle to steamflood, was recognizable less as discrete beds that could be correlated from well to well than as a dominant lithologic element within a stratigraphic interval of limited areal extent. Only one such interval, referred to as the "Middle Marker Unit", exhibited continuity across nearly the entire pilot site. The presence of this marker unit, just 5-15 ft in thickness, provides a basis to divide the Monarch Sand into three stratigraphic elements - an Upper Sand, the Middle Marker, and a Lower Sand.

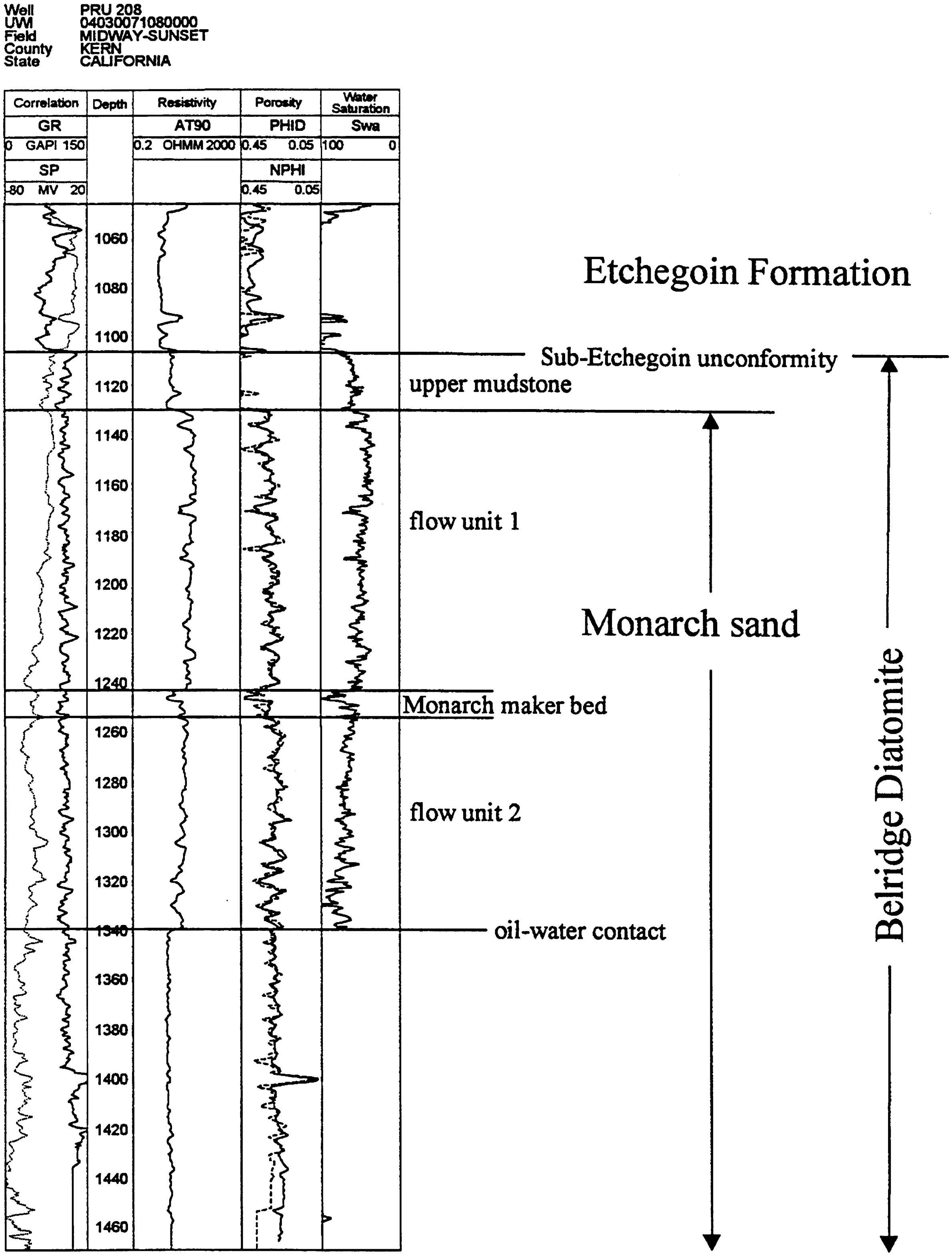

Figure 3. Type log of the Monarch sand of the Belridge Diatomite Member of the Monterey Formation. Muddy lithofacies are interpreted as beds that have porosity greater than 35 percent. The upper mudstone is interpreted as Belridge Diatomite mud which depositionally overlies the Monarch sand This formation is probably a steam barrier. The Monarch marker bed is interpreted as a mudstone that is a local steam baffle.

Even with the high density of quality log suites from the 20 wells drilled expressly for this project, it proved impossible to develop a multi-layer stratigraphic model for the Monarch Sand at this location. The apparent absence of lateral continuity and limited variation in log responses between the lithofacies observed in core severely limit high-resolution stratigraphic modeling of this sand reservoir at this site.

The previous stratigraphic model of the Monarch Sand developed in first phase of the project, which was based mainly on resistivity curves, has been substantially revised. It is now clear that the various correlation surfaces developed in that older model are ungrounded. Only the "Surface 3" correlation, which corresponds to the base of the "Middle Marker Unit" in the current model, is valid. Unfortunately, no further correlation within the Monarch Sand are possible at the site of the Pru pilot demonstration.

In the southeastern half of the pilot site, the Monarch Sand is overlain by a diatomaceous mudstone, presumably the enclosing Belridge Diatomite Member, which is erosionally beveled and absent beneath the base Etchegoin unconformity towards the northwest. This mudstone also is delineated on the basis of gamma ray and porosity log response (Figure 3-3). The Etchegoin Formation, however, is easily recognized in resistivity logs, as is the oil-water contact within the Monarch Sand.

Subsurface Configuration of the Monarch Sand

The four structural cross sections and two structure contour maps presented here depict the subsurface configuration of the Monarch Sand. Each cross section (Fig. 4 through Fig. 7) shows the Etchegoin Formation, the base Etchegoin unconformity, and the Monarch Sand all dipping southeastward. The southeastern dip also is clear in the structure contour maps (Fig. 8 and Fig. 9). The base Etchegoin unconformity dips approximately 8° SE, whereas the underlying Monarch Sand dip is slightly steeper, about 16° SW. The sub-Etchegoin unconformity bevels northwestward across both the Belridge Diatomite mudstone above the Monarch Sand and higher portions of the "Upper Sand Unit".

The upper Belridge Diatomite mudstone is identified in wells in the southern and southeastern part of the part of the pilot site, where it reaches a maximum thickness of 33 ft. It is absent beneath the base Etchegoin unconformity to the northwest (Fig. 3-4 through Fig. 3-7). A second mudstone-dominated layer, the "Monarch Marker Unit", is identified in most wells, except those in the extreme northwest. This broadly defined muddy unit thins from a maximum of 22 feet in the southeastern part of the pilot site northwestward to be cut out by the "Upper Sand Unit" as shown in Fig. 3-9. Northwest of the limit of the "Monarch Marker Unit" the Monarch Sand cannot be divided reliably on the basis of log interpretation.

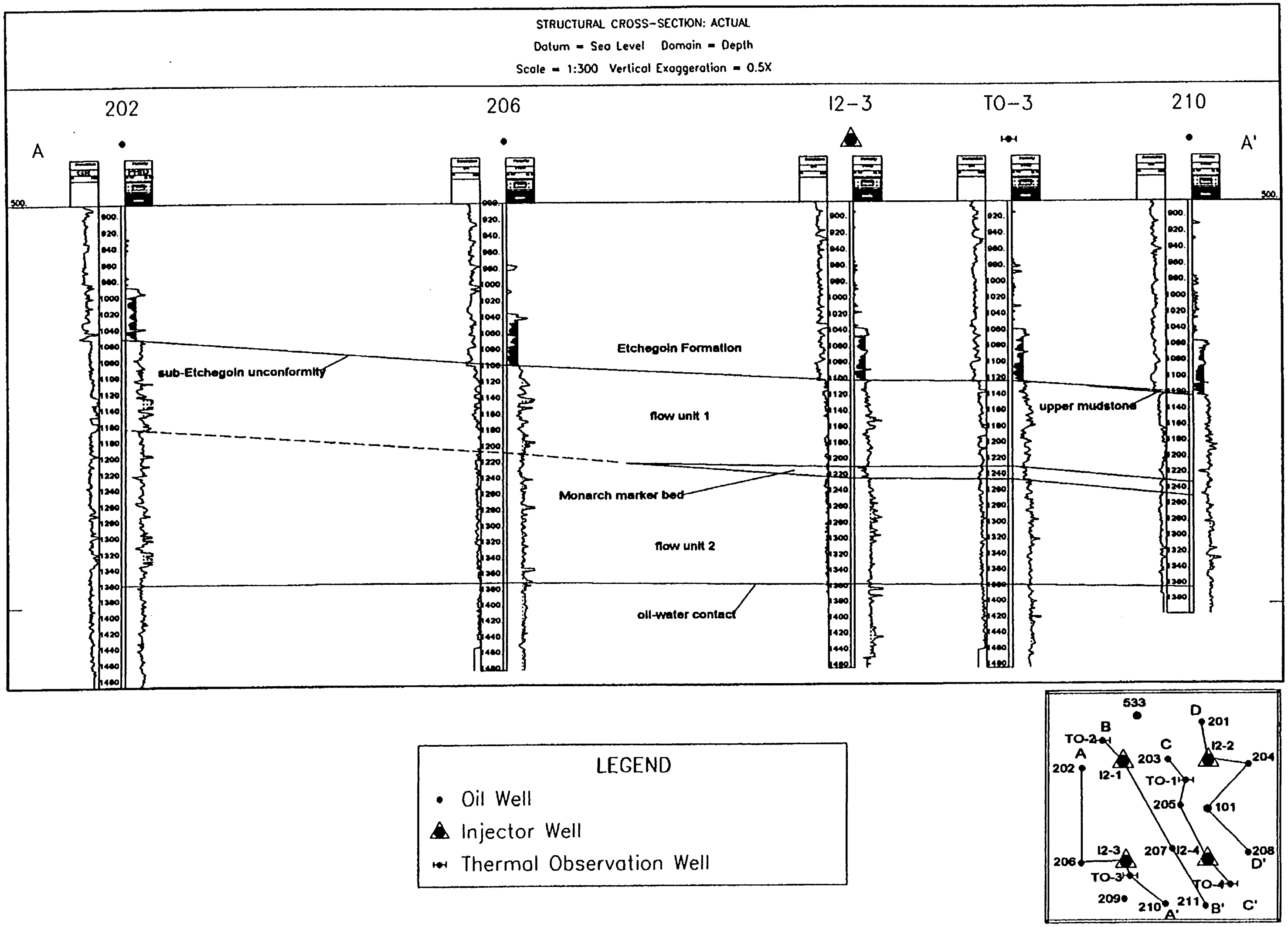

Figure 4. Structural cross section A-A'. The Monarch sand underlies the sub-Etchegoin unconformity and consists of the upper mudstone, flow unit 1, the Monarch marker bed, and flow unit 2. These units dip about 16° southeast and the overlying Etchegoin Formation dips about 8° southeast. The gamma ray curve is on the left and the density porosity curve is on the right. Porosity over 35 percent is blackened to the left and porosity less than 26 percent is stippled to the right.

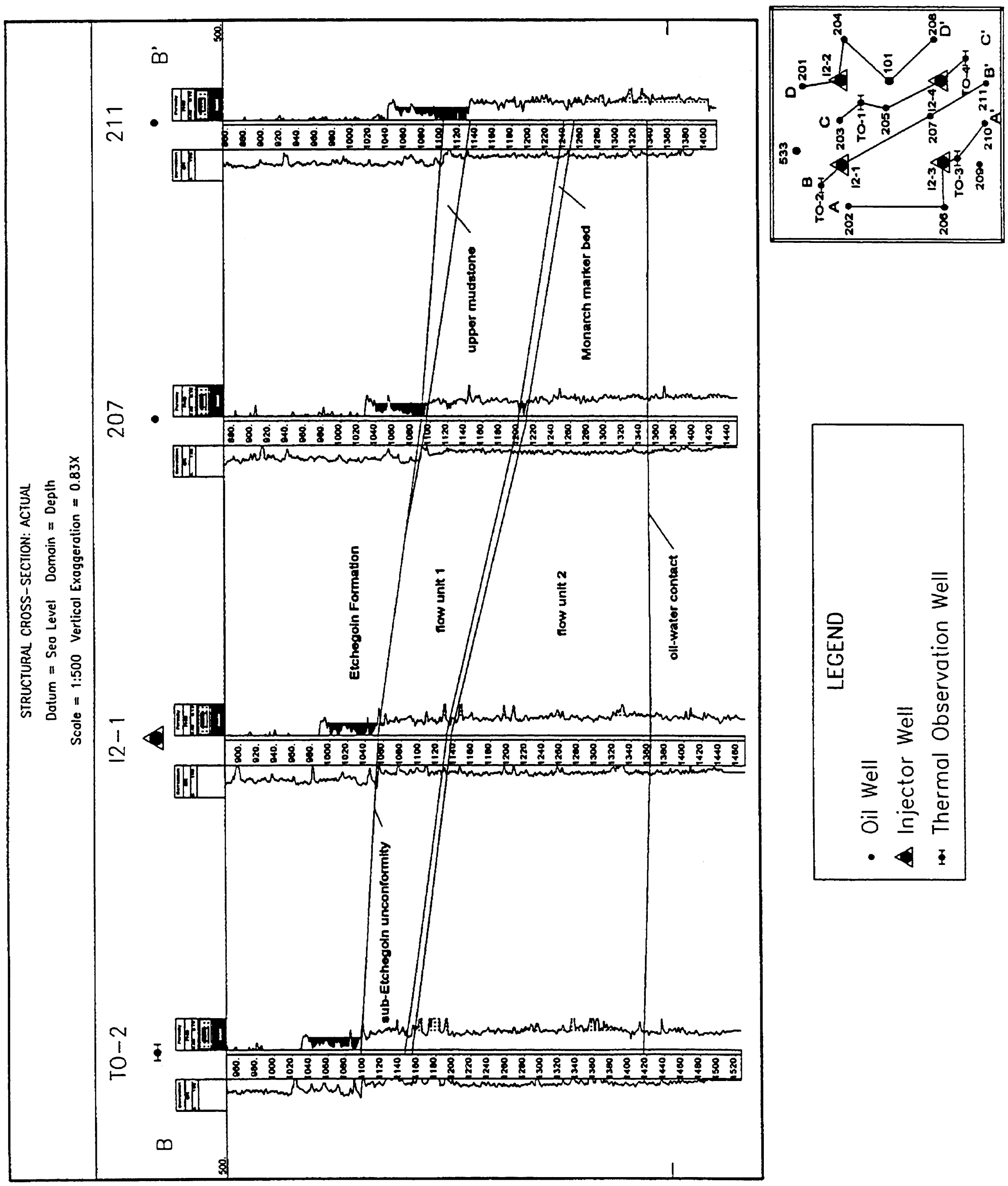

Figure 5. Structural cross section B-B'. The Monarch sand underlies the sub-Etchegoin unconformity and consists of the upper mudstone, flow unit 1, the Monarch marker bed, and flow unit 2. These units dip about 16° southeast and the overlying Etchegoin Formation dips about 8° southeast. The gamma ray curve is on the left and the density porosity curve is on the right. Porosity over 35 percent is blackened to the left and porosity less than 26 percent is stippled to the right.

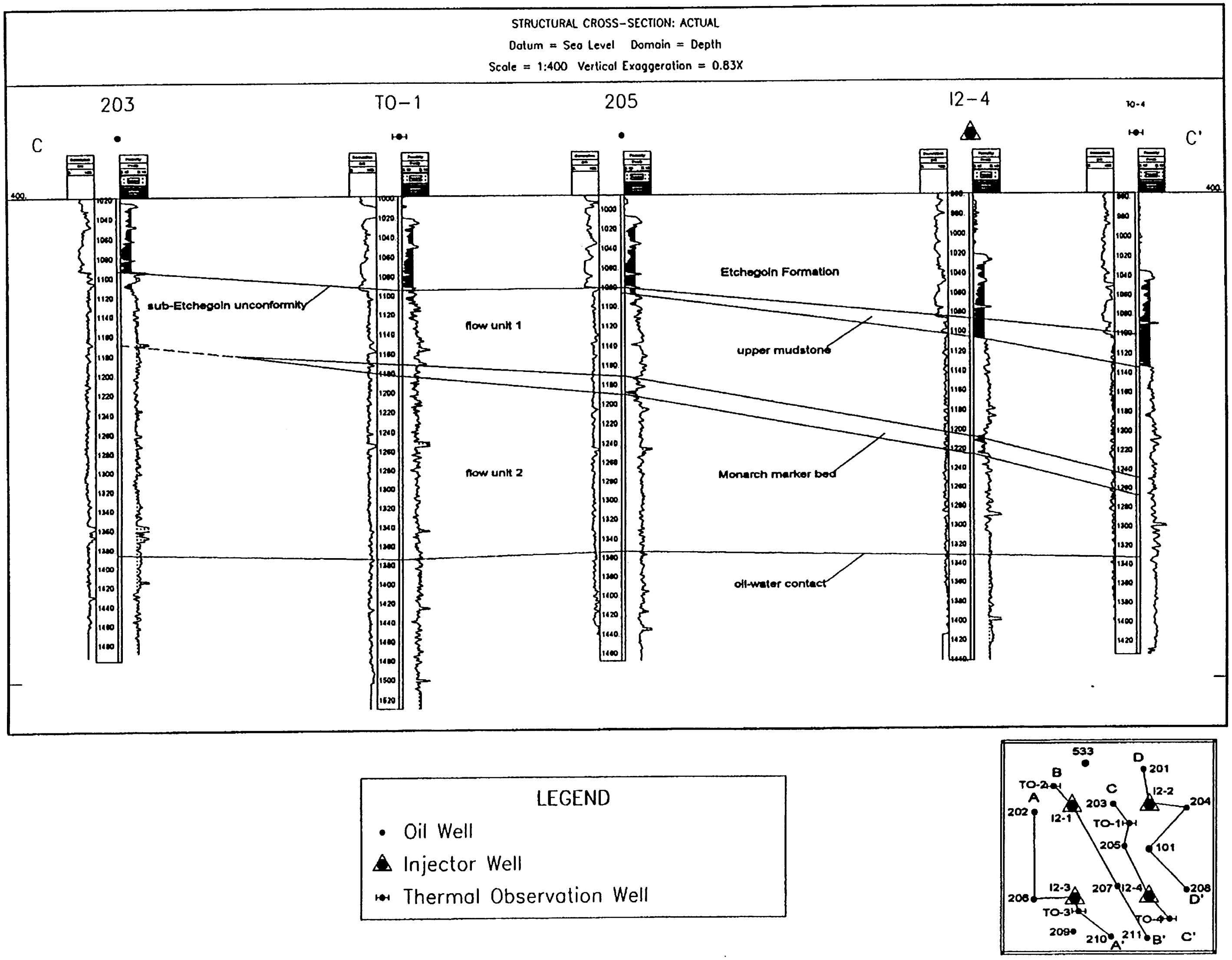

Figure 6. Structural cross section C-C'. The Monarch sand underlies the sub-Etchegoin unconformity and consists of the upper mudstone, flow unit 1, the Monarch marker bed, and flow unit 2. These units dip about 16° southeast and the overlying Etchegoin Formation dips about 8° southeast. The gamma ray curve is on the left and the density porosity curve is on the right. Porosity over 35 percent is blackened to the left and porosity less than 26 percent is stippled to the right.

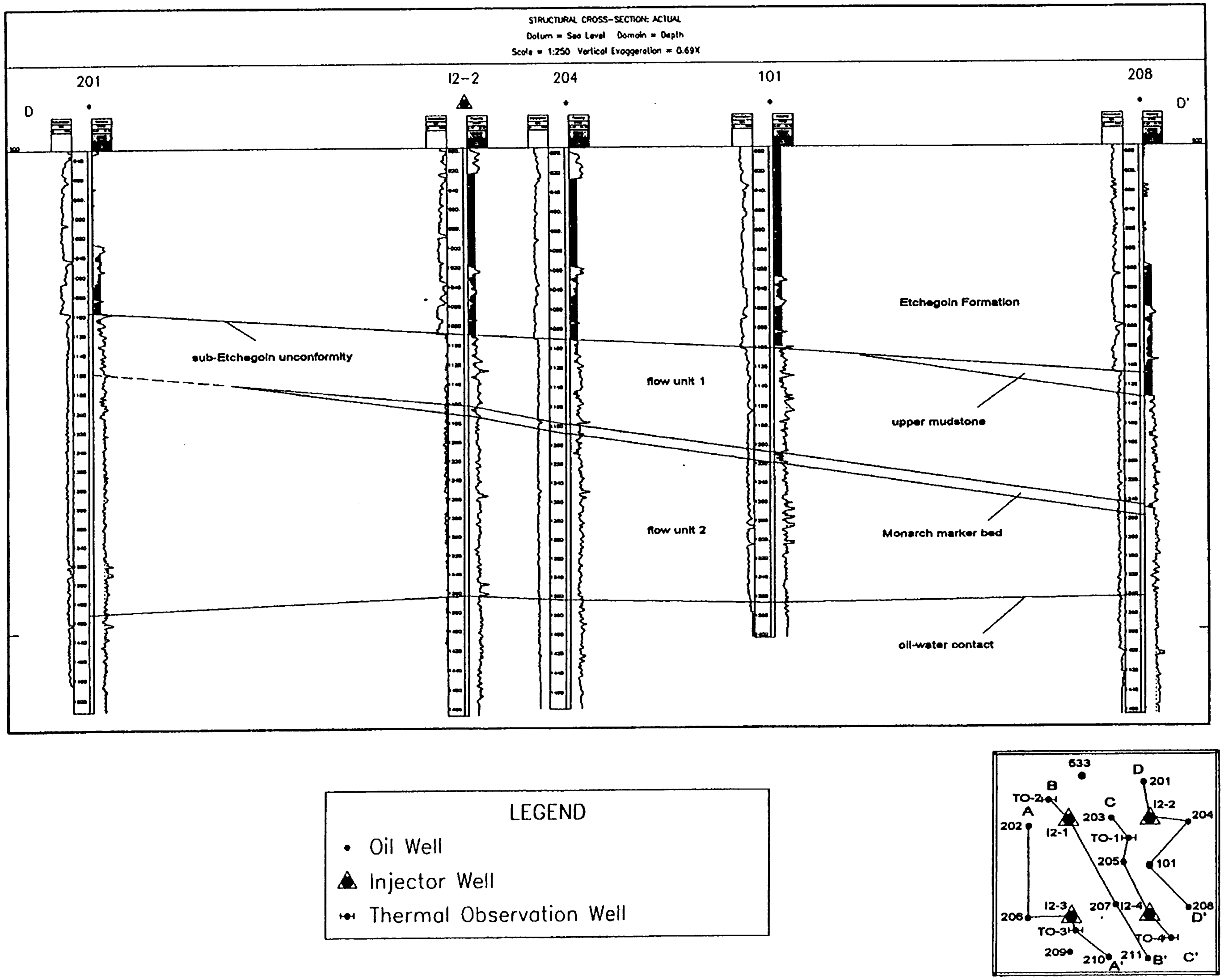

Figure 7. Structural cross section D-D'. The Monarch sand underlies the sub-Etchegoin unconformity and consists of the upper mudstone, flow unit 1, the Monarch marker bed, and flow unit 2. These units dip about 16° southeast and the overlying Etchegoin Formation dips about 8° southeast. The gamma ray curve is on the left and the density porosity curve is on the right. Porosity over 35 percent is blackened to the left and porosity less than 26 percent is stippled to the right.

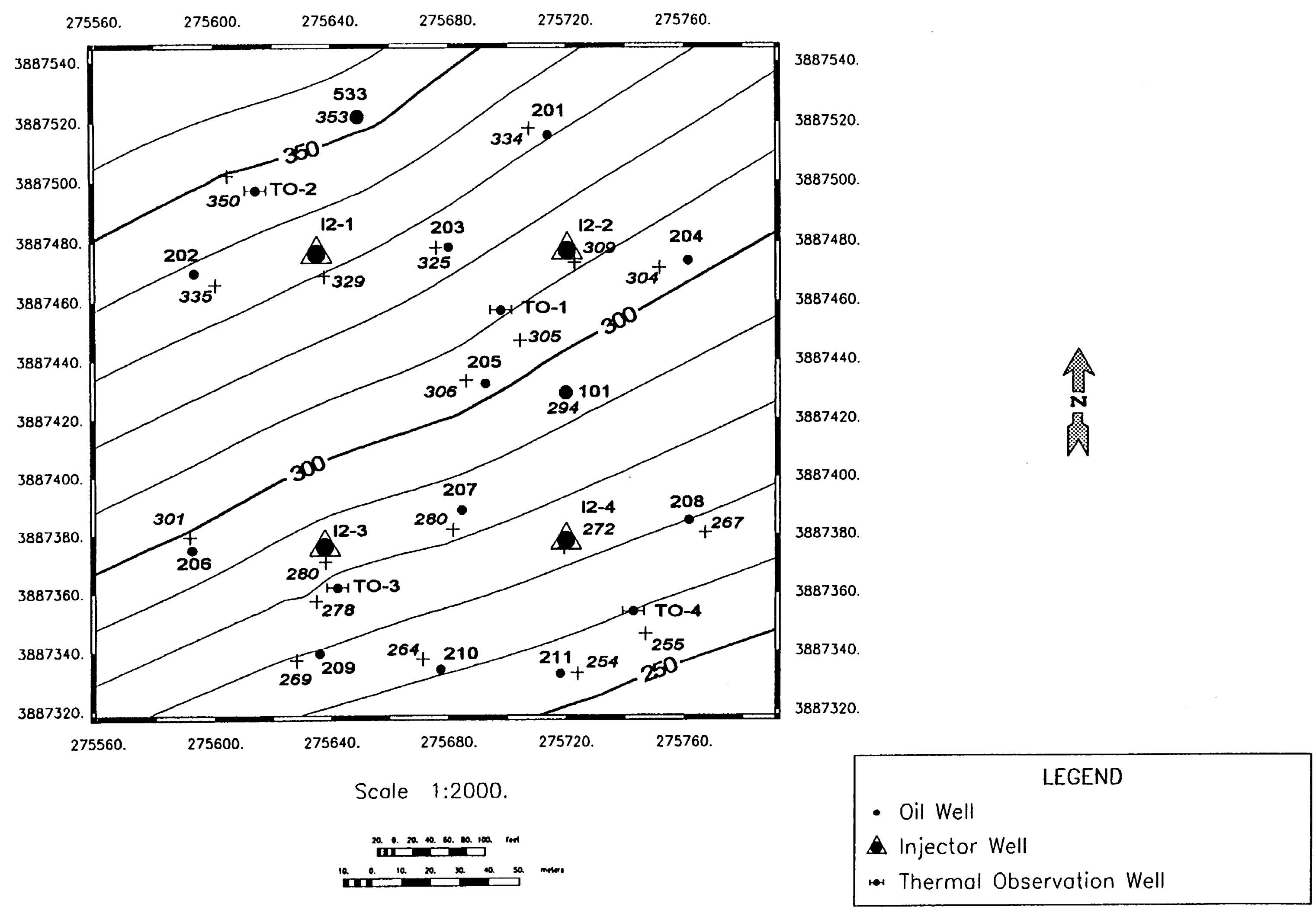

Figure 8. Structure contour map on the sub-Etchegoin unconformity. The unconformity and overlying Etchegoin Formation dips about 8° southeast. The italic numbers are the subsea values (in feet) for the sub-Etchegoin unconformity. The plus symbol indicates the down hole location of the top of the sub-Etchegoin unconformity. The contour interval is 10 feet. Map coordinates are in UTMs, zone 11.

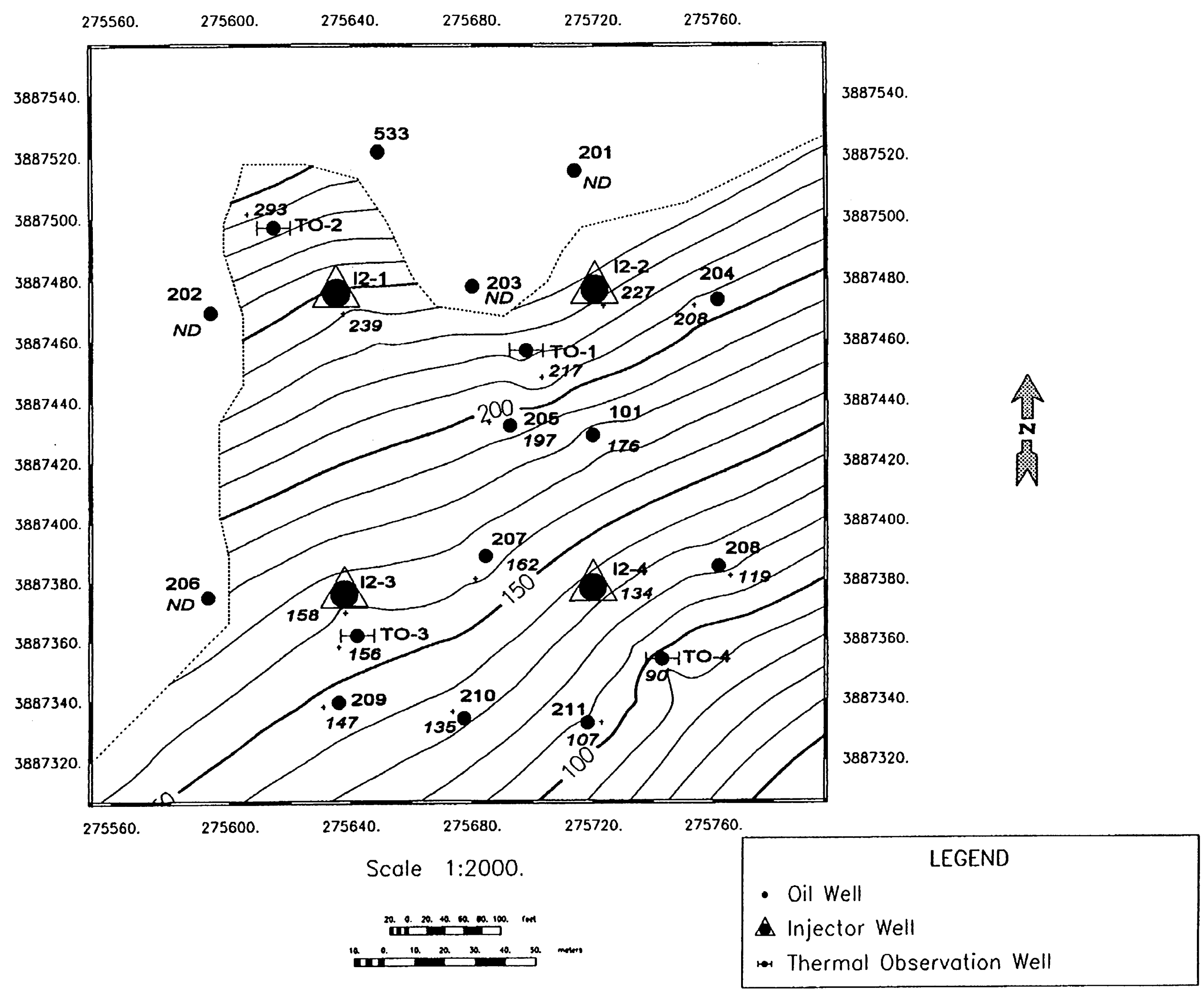

Figure 9. Structure contour map on the base of the Monarch marker bed. The Monarch marker bed pinches out or is scoured out by the overlying flow unit 1 in the northwest part of the study area. The dashed line represents the approximate limit of the Monarch marker bed. The italic numbers are the subsea values (in feet) for the base of the Monarch marker bed and ND represents where the base of the Monarch marker bed is missing. The plus symbol indicates the down hole location of the base of the Monarch marker bed. The contour interval is 10 feet. Map coordinates are in UTMs, zone 11.

The sub-Etchegoin unconformity and upper mudstone are interpreted as steam barriers and the Monarch marker bed is interpreted as a baffle. Steam should be effectively contained along the barriers; however, steam will probably migrate in the updip direction along the base of the Monarch Marker Unit and then upward where this unit is missing.

The oil-water contact (Fig. 3-8) was penetrated in all of the 20 wells. It is generally sub-planar and horizontal, 20 to 40 feet above sea level as depicted on the cross sections (Fig. 3-4 through Fig. 3-7). This configuration and depth are consistent the oil-water contact mapped in an earlier phase of the project across a considerably larger area using a different set of wells.

The gross pay of the Monarch Sand is defined as the oil saturated interval between the base Etchegoin unconformity and the oil-water contact (OWC) in the northwest and between the base of the upper Belridge Diatomite mudstone and the OWC in the southeast. The gross pay thins southeastward from approximately 300 ft. to just 200 ft due to the southeastern dip of the reservoir through the OWC and the insertion of the Belridge Diatomite mudstone above the Monarch Sand.

The stratigraphy and structure of the Monarch reservoir at the pilot site is consistent regionally with the stratigraphy and structure of the Monarch Sand as described by Sturm (1996).

Chapter 4

Geostatistical Modeling Using Heresim3D™

In an early stage of demonstration phase (BP-2) of the Midway-Sunset project 18 new wells were drilled and logged (Fig. 4-1). The new wells complete the pattern of injector, producer and thermal observation wells required for an 8 ac pilot steam flood at the Pru Lease. Modern geophysical logs run in each hole provide a sound foundation for improving the geological and petrophysical models needed as input for reservoir simulation.

In the characterization phase (BP-1) of the project, it was necessary to rely on a set of geophysical logs obtained from wells completed during many decades of exploration and development within and near the Pru Lease. Only three modern, reliable log suites were available for the Pru Lease. These were the logs for a cored well, Pru-533, and the two new project wells, Pru-101 and TO-1. Thus, geological and petrophysical models developed during BP-1 were based primarily on data obtained outside the Pru, particularly from the adjacent AWE Kendon lease which is under active development. Drilling and logging of the 18 new wells within the Pru Lease enabled us to increase our confidence in the geological and petrophysical models developed within the relatively small reservoir volume involved in the 8 ac pilot.

The sequence of steps involved in building new geological and petrophysical models (Table 4-1) is essentially the same as that followed during the characterization phase. The reader is referred to 1996 annual report for this project. The 20 new suites of

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Table 4-1: Modeling Procedure

- **Set up reservoir modeling domain** by establishing grid and model limits;
- **Define lithotype characteristics** discernible in well logs; lithotypes are pebbly sand, sand, and diatomaceous mudstone;
- **Compute distribution of lithotypes** conditioned by variogram models, vertical proportion curves, and lithotypes at each well;
- **Develop detailed stochastic petrophysical models** for statistical distribution of porosity and permeability;
- **Upscale the petrophysical models** and transfer to reservoir simulator.

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geophysical logs were used to redefine the geometry of the primary *lithofacies* and their bounding surfaces. Once defined, the lithofacies and bounding surfaces were imported into Heresim3D™. This software was used, in turn, to develop stochastic geological models within the area shown in Fig. 4-1. Combining a series of geological realizations with petrophysical measurements obtained from Pru 101 core analyses yields a series of petrophysical models needed as input to a new round of reservoir simulation. One realization has been constructed and a preliminary set of reservoir simulations are underway. A full set of geological and petrophysical models will be developed to test the possible impact of geological variability within the 8 ac Pru pilot site once the results of the ongoing simulations are fully analyzed.

Each lithofacies incorporated in the geological model is defined through qualitative assessment of the new geophysical logs combined with the logs Pru 101 and Pru TO-1 obtained during the initial phase. Four lithofacies (pebbley sand, coarse to medium sand, fine sand, mudstone) were modeled in the initial phase. However, the petrophysical properties of the medium and fine sand lithofacies were determined to be very similar. Therefore, for the current geostatistical modeling we elected to define only three lithofacies - pebbley sand, coarse to fine sand, mudstone. The "mudstone" class is actually a silty diatomite. A statistical description of the permeability and porosity values assigned to each lithofacies is given in Table 4-2.

Table 4-2 - Lithofacies Permeability and Porosity

Facies Description		Permeability (md)				Porosity (%)			
		Min.	Max.	Mean	S.D.	Min.	Max.	Mean	S.D.
1	Pebbley Sand	748	4133	2277	1038	24.9	32.9	28.6	2.2
2	Coarse-Fine Sand	185	6000	2841	2356	26.2	43.6	31.9	2.4
3	Mudstone	10	200	35	10	32.0	38.0	35.0	1.0

An important difference between the initial (BP-1) and the current (BP-2) geological model is reflected in the number of *lithotypes* or stratigraphic modeling elements incorporated in the geological model. Whereas just two lithotypes, an upper and a lower, were defined in the earlier modeling, three lithotypes are defined in the current modeling (Fig. 4-2). The new lithotype (middle lithotype) represents a discontinuous, lower permeability layer between the upper and lower lithotypes (Fig. 4-2). We anticipate that incorporating the middle lithotype will help improve our ability to mimic the progress of the pilot flood.

A recent enhancement to the Heresim3D™ software provides an opportunity to mimic non-stationarity within the 3-D geostatistical model of lithofacies. In the initial phase only one *vertical proportion curve* could be constructed. It was applied across the entire model domain. In the current modeling a different vertical proportion curve is constructed at each well as a basis for developing an interpolated variation in proportion curve properties throughout the model domain (Fig. 4-3). Several different matrices of curves were constructed using a variety of interpolation rules until the most geologically plausible result was obtained. A 10 x 10 matrix of vertical proportion curves was developed for each of the three lithotypes. Fig. 4-3 shows the result obtained for the upper lithotype.

The vertical proportion curves and corresponding *variograms* are used in Heresim3D™ to construct a realization of plausible geological variability at the Pru Lease. Figs. 4-5, 4-6 and 4-7 show lithofacies distributions typical of each lithotype. The X and Y dimensions of the gridblocks shown in Figs. 4-5, 4-6 and 4-7 are both equal to 4 meters. Subtle, but possibly important, differences in the variogram models derived for each lithofacies (Fig. 4-4) lead to characteristic differences in the lithofacies patterns.

A NW-SE cross-section (Fig. 4-8) shows the vertical distribution of lithofacies computed using Heresim3D™. The Z dimension of the gridblocks is, on average, about 0.5 m throughout the model domain. As in the bedding-parallel sections of Figs. 4-5, 4-6 and 4-7, the vertical section shows clear differences in the facies architecture associated with each lithotype.

Values for the petrophysical properties associated with each facies type (Table 2-2) are distributed statistically within each facies applying *log normal* distributions for permeability and *normal* distributions for porosity. Heresim3D™ does not provide an option for including spatially correlated petrophysical properties within each facies type, but such a refinement is not justified by the data constraint of a single core. Figs. 4-9 through 4-13 illustrate the stochastic permeability and porosity distributions obtained in one realization of the geological model.

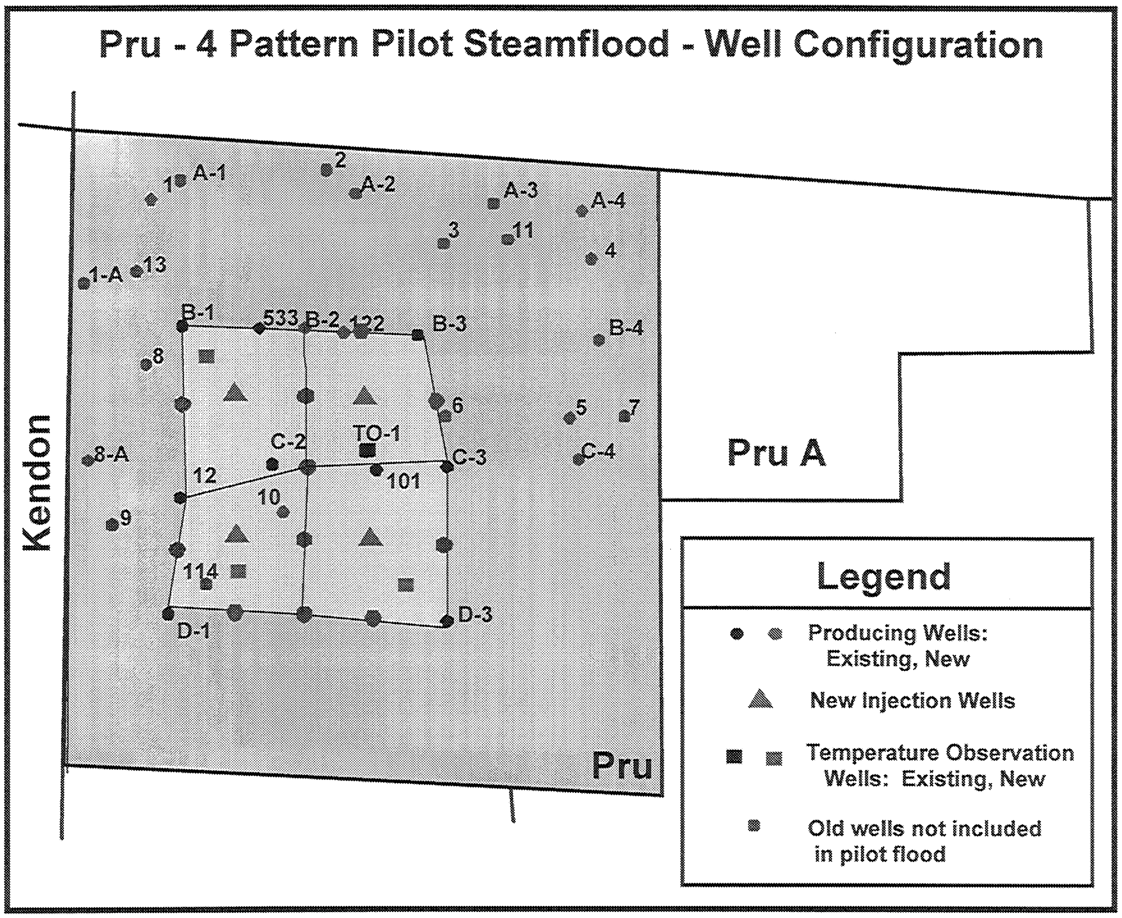
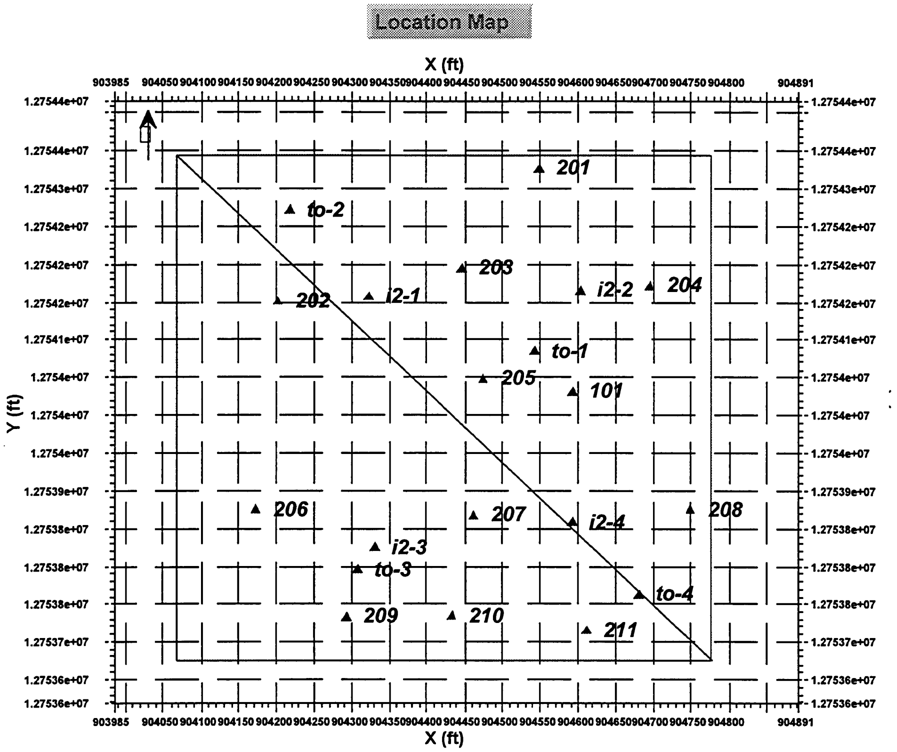


Figure 4-1. Location map showing existing and new wells at the Pru Lease.



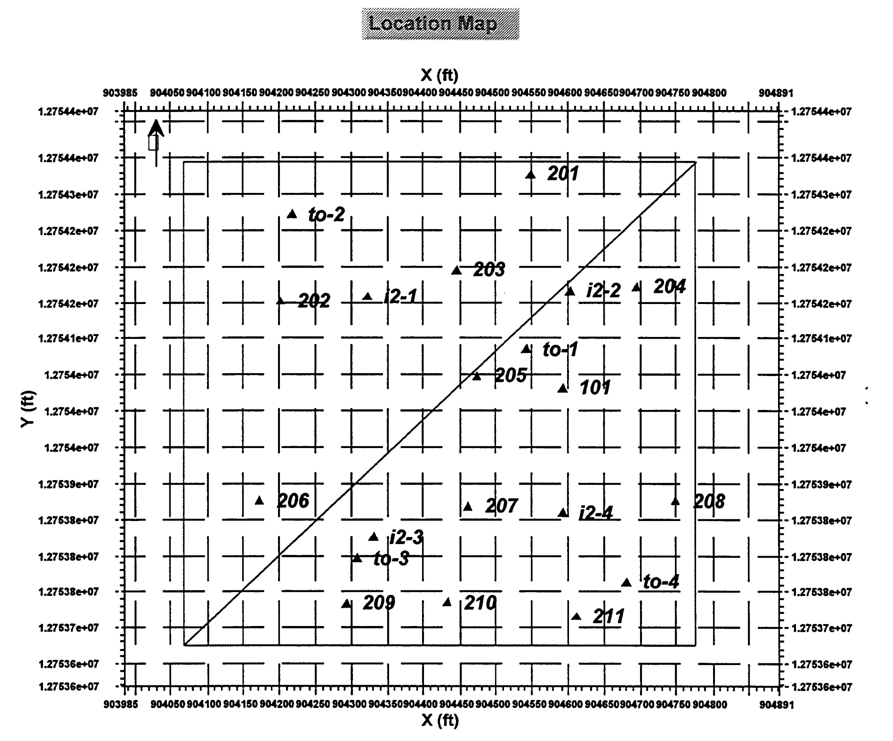


Figure 4-2 . Vertical sections showing the three lithotypes incorporated in the geological model: a) northwest-southeast section, and b) southwest-northeast section. Cross-section locations are shown in Figure 1.

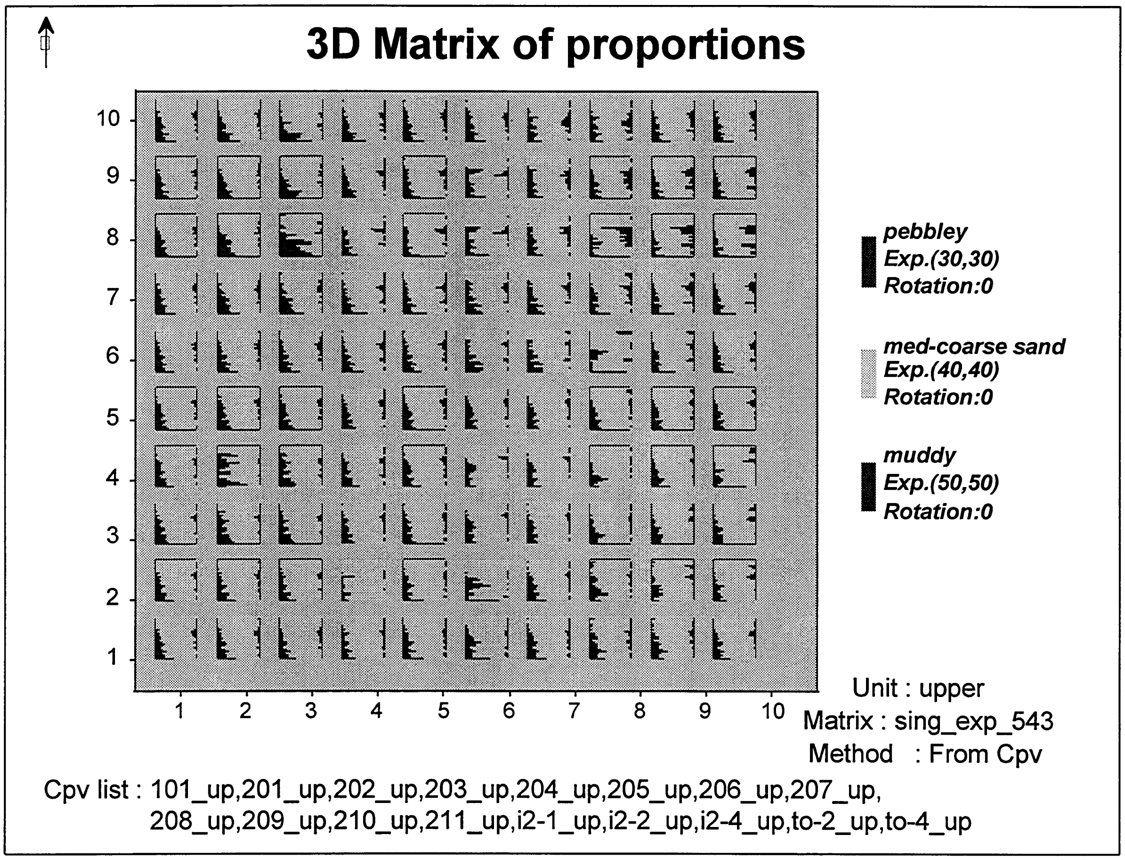
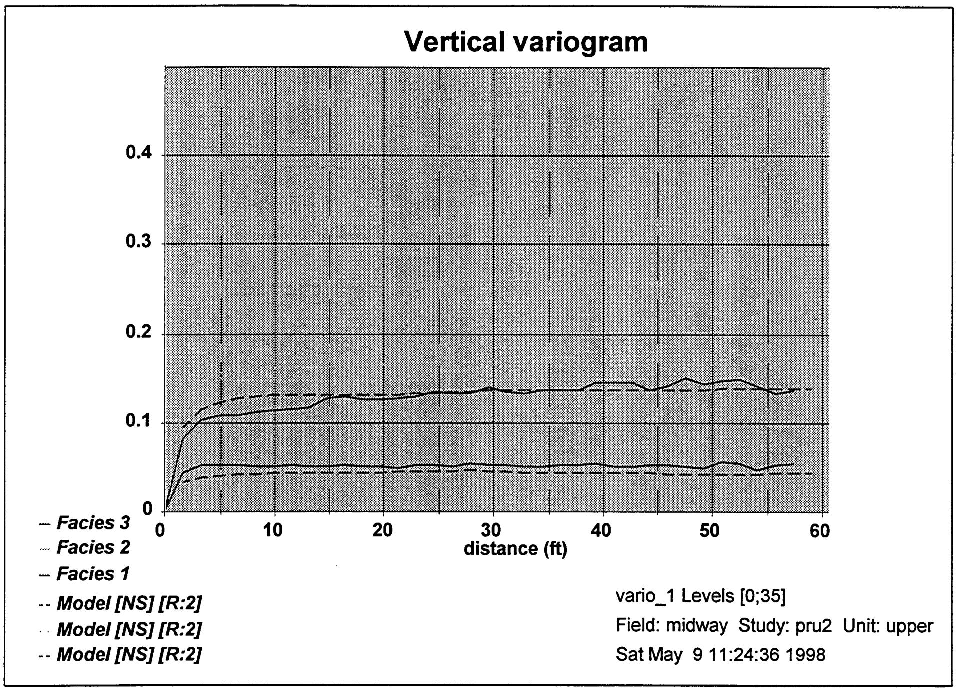


Figure 4-3. Matrix of vertical proportion curves used to represent non-stationarity in lithofacies distributions within the model domain for the upper lithotype.



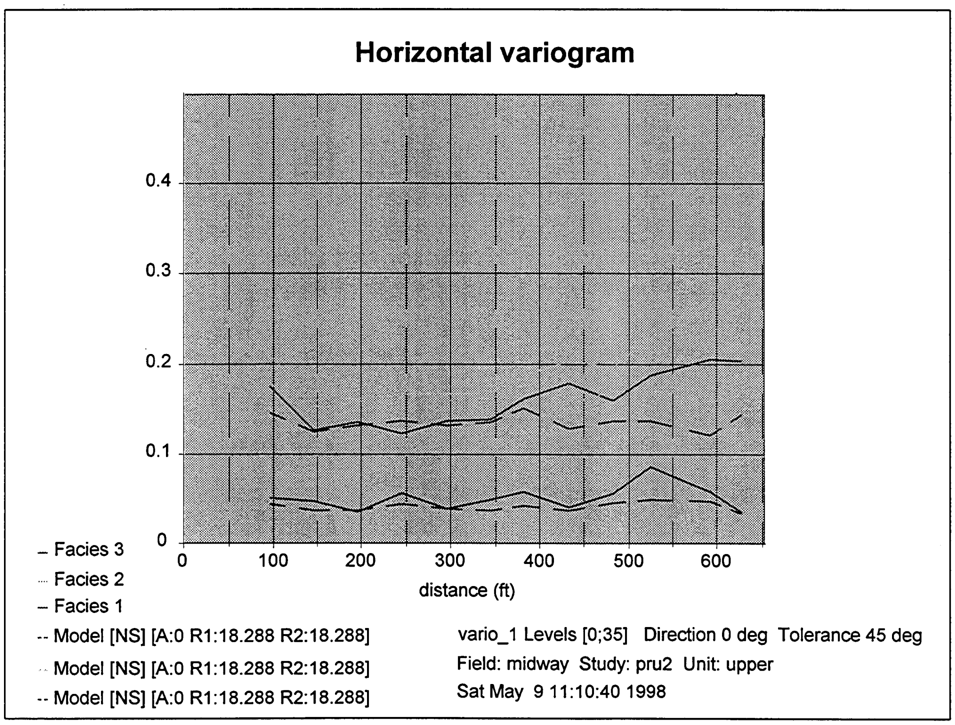


Figure 4-4. Vertical and horizontal variograms computed for the three lithofacies contained within two lithotypes shown in Figure 2: a) upper lithotype, and b) middle lithotype

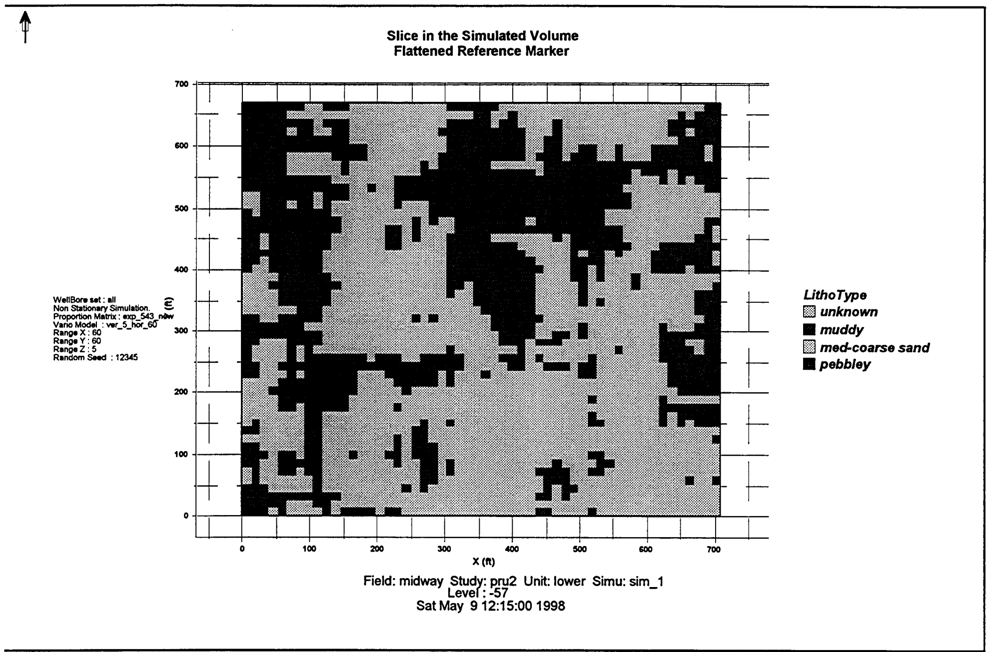


Figure 4-5. Bedding-plane parallel section of lithofacies cut from within the upper lithotype.

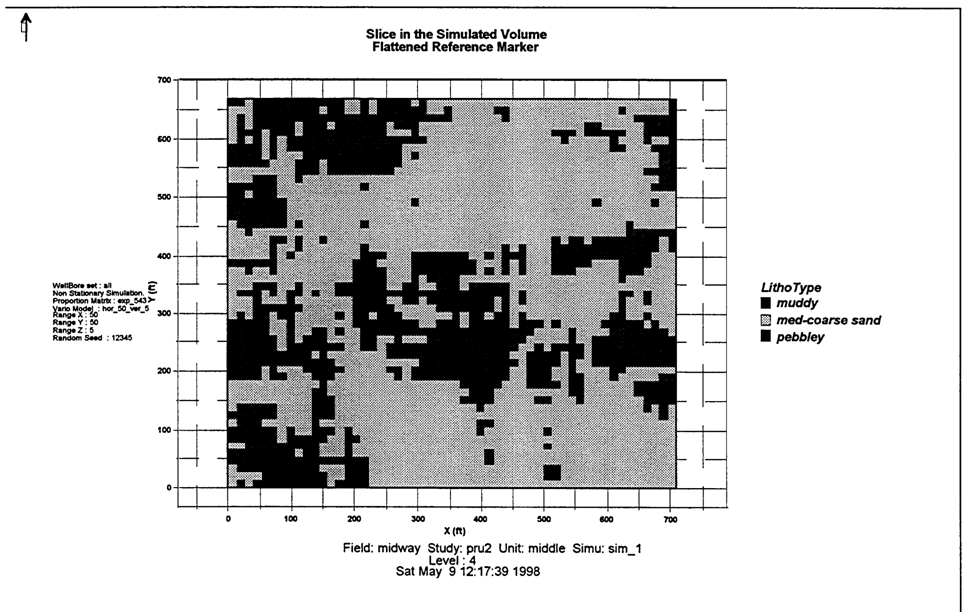


Figure 4-6. Bedding-plane parallel section of lithofacies cut from within the middle lithotype.

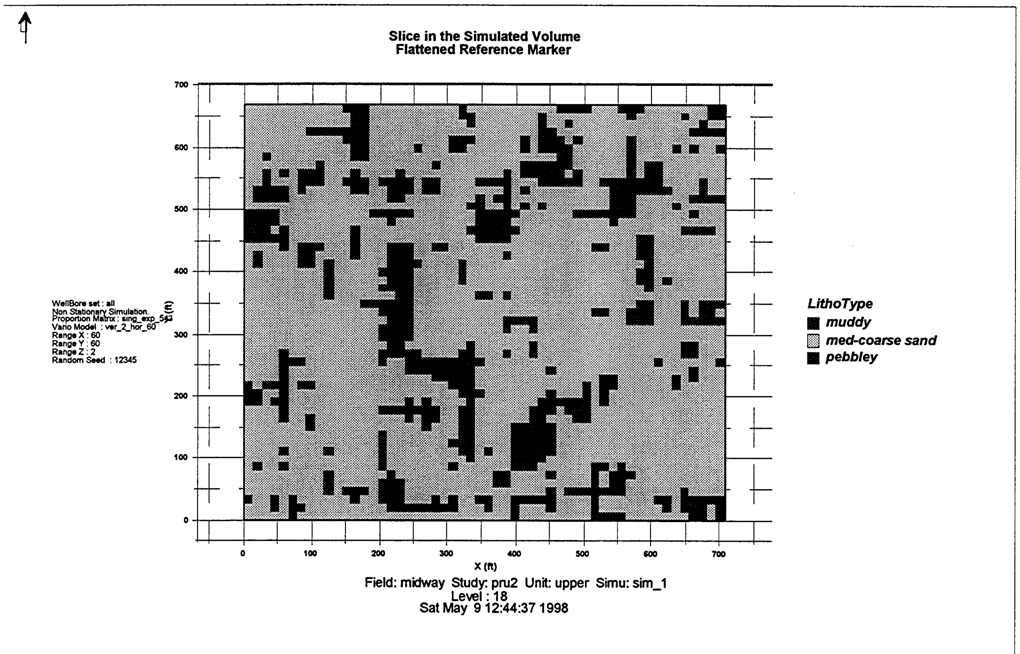


Figure 4-7. Bedding-plane parallel section of lithofacies cut from within the lower lithotype.

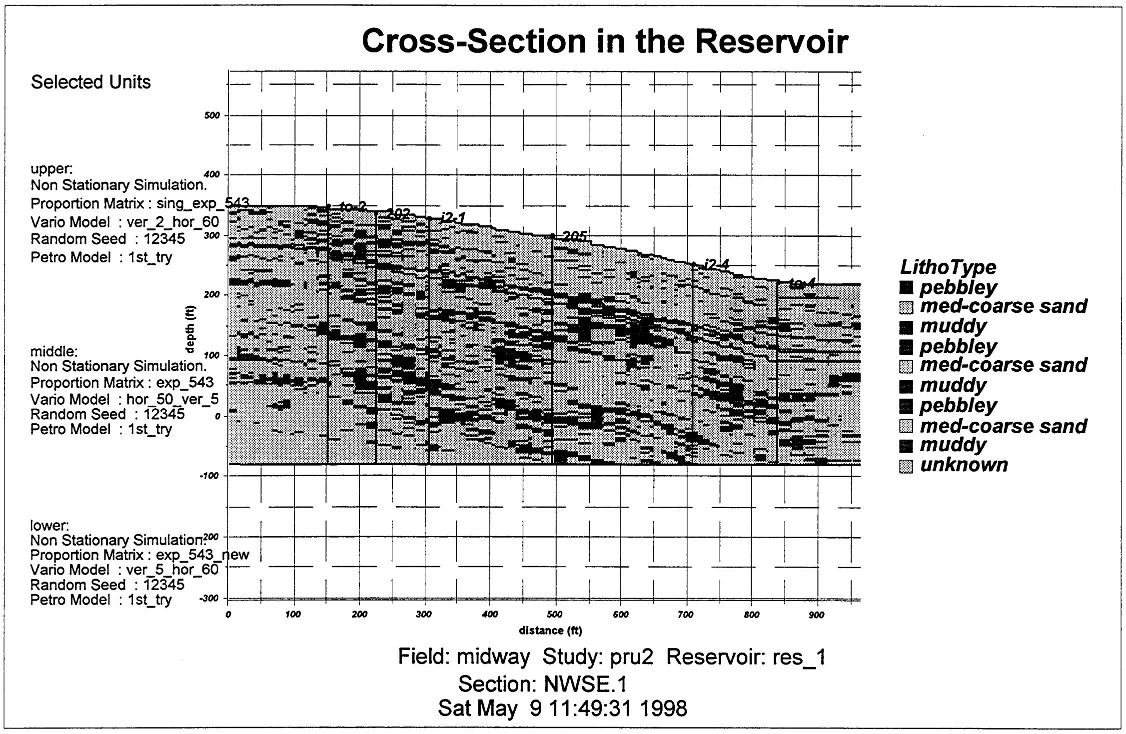


Figure 4-8. Vertical cross-section showing lithofacies within a northwest-southeast section. Cross-section location is shown in Figure 1.

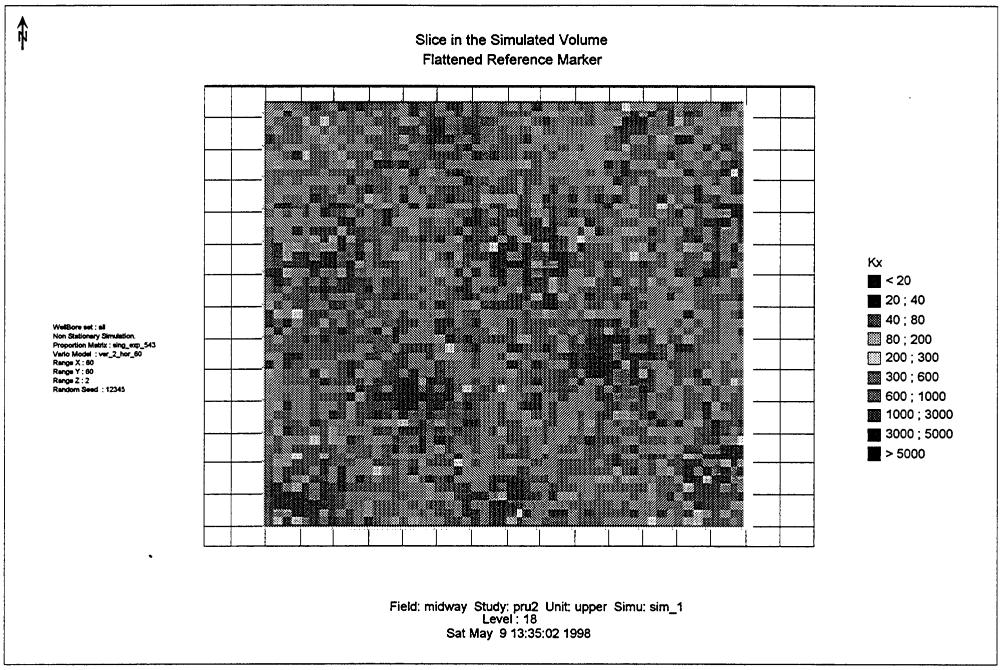


Figure4- 9. Bedding-plane parallel section of permeability cut from the upper lithotype.

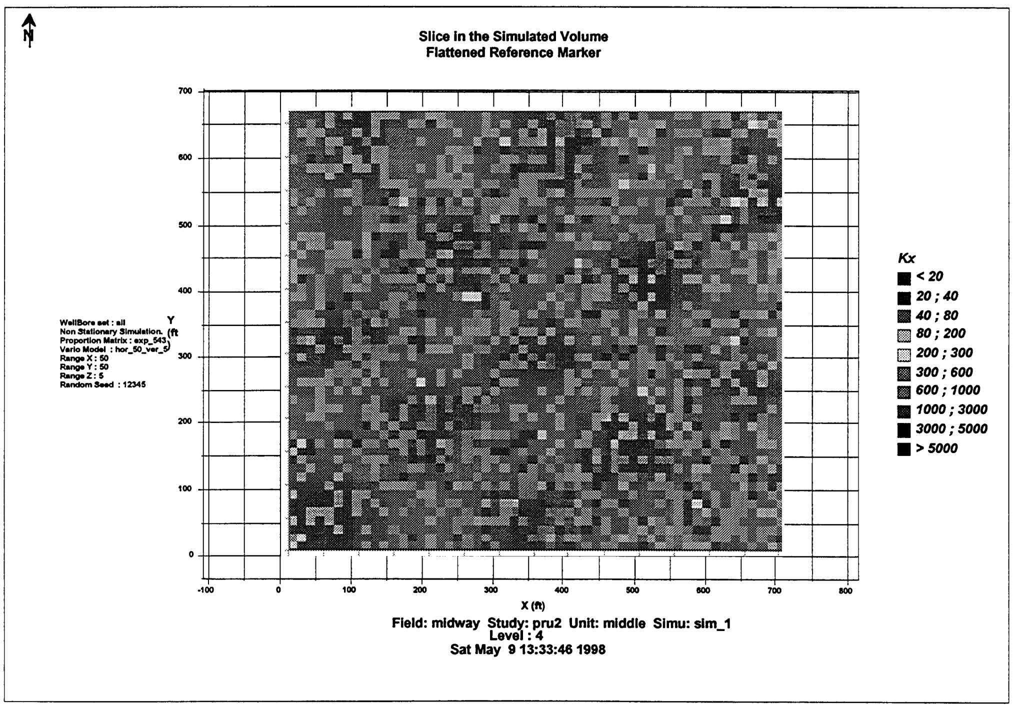


Figure 4-10. Bedding-plane parallel section of permeability cut from the middle lithotype

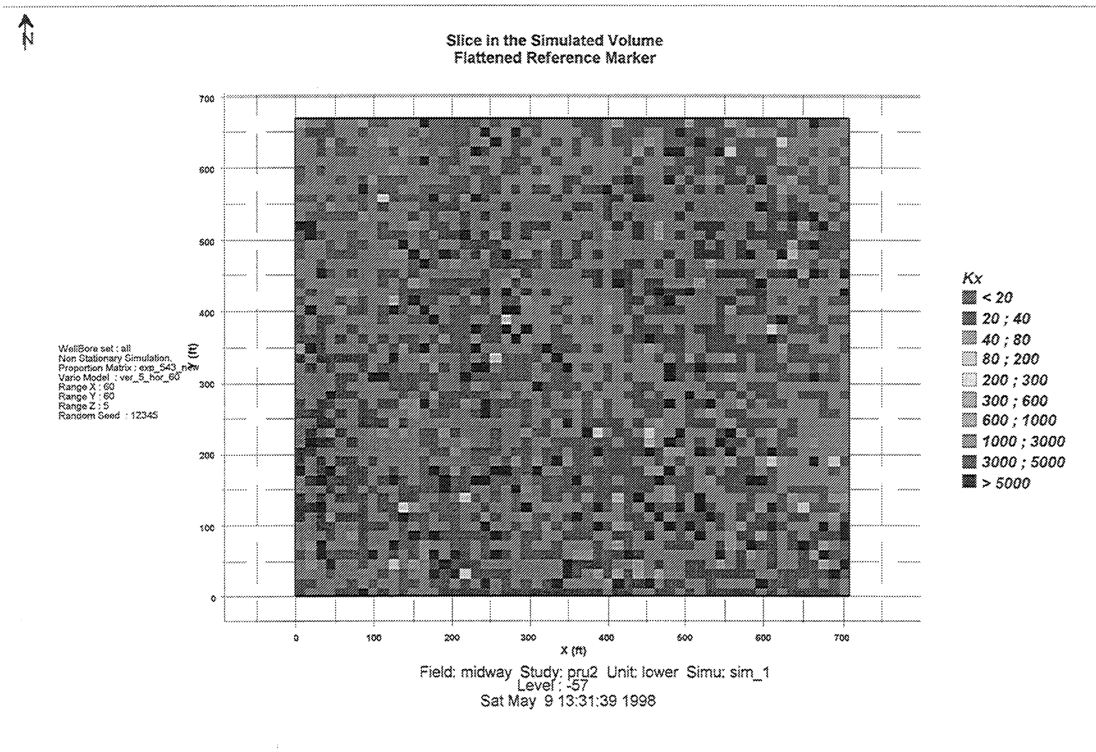


Figure 4-11. Bedding-plane parallel section of permeability cut from the lower lithotype.

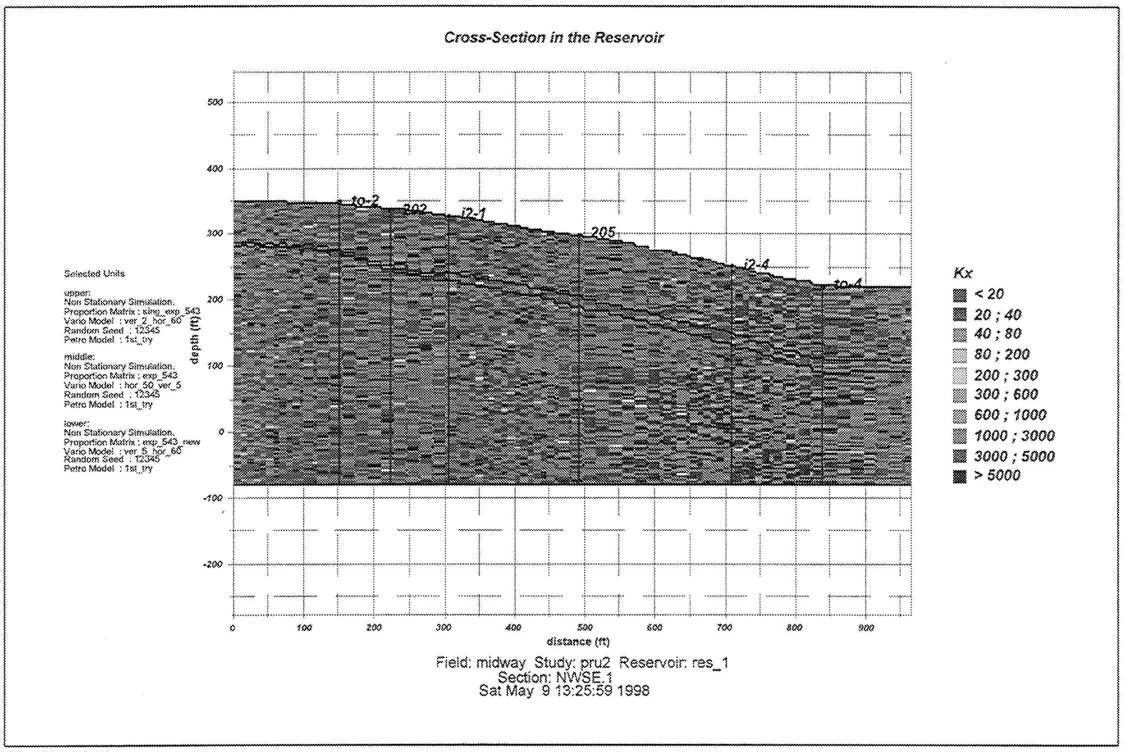


Figure 4-12a. Vertical cross-sections showing computed permeability within a northwest-southeast section. Cross-section locations are shown in Figure 1.

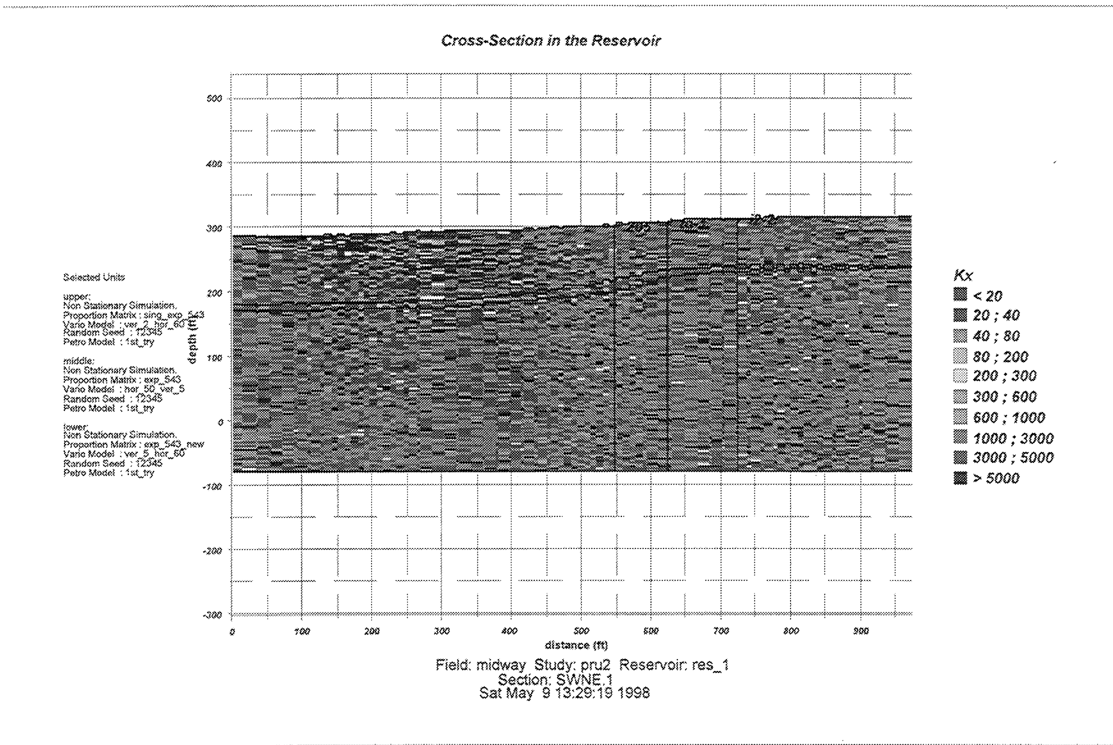
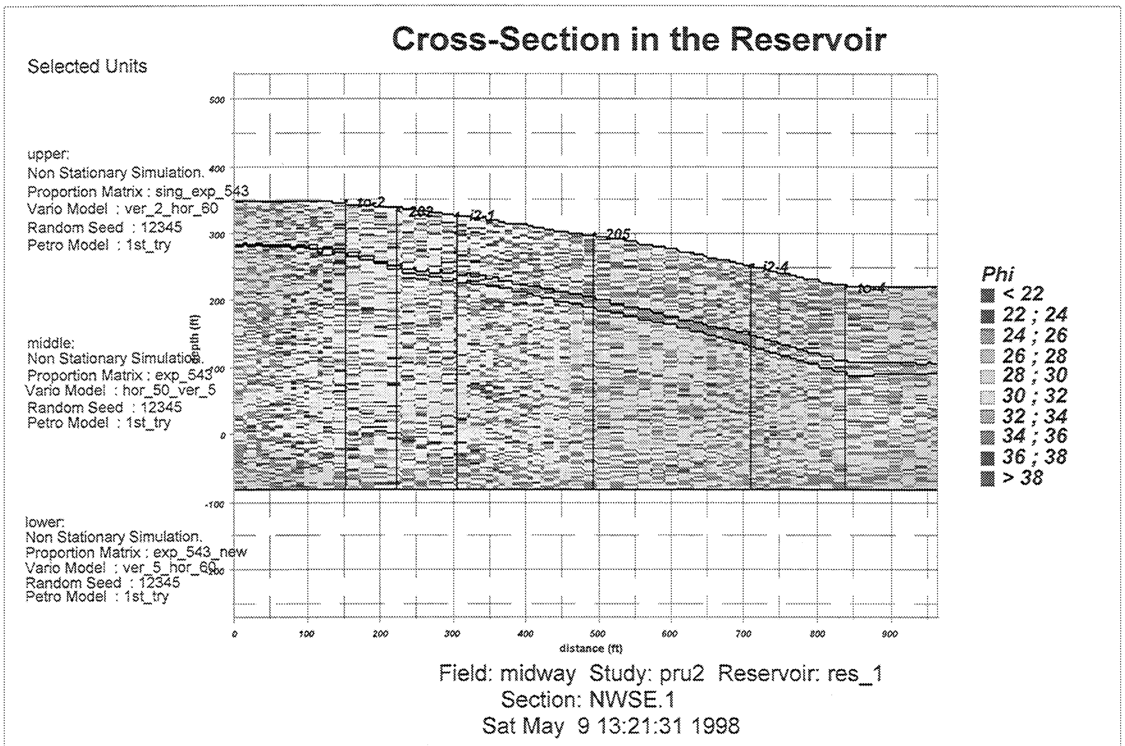


Figure 4-12b. Vertical cross-sections showing computed permeability within a southwest-northeast section.



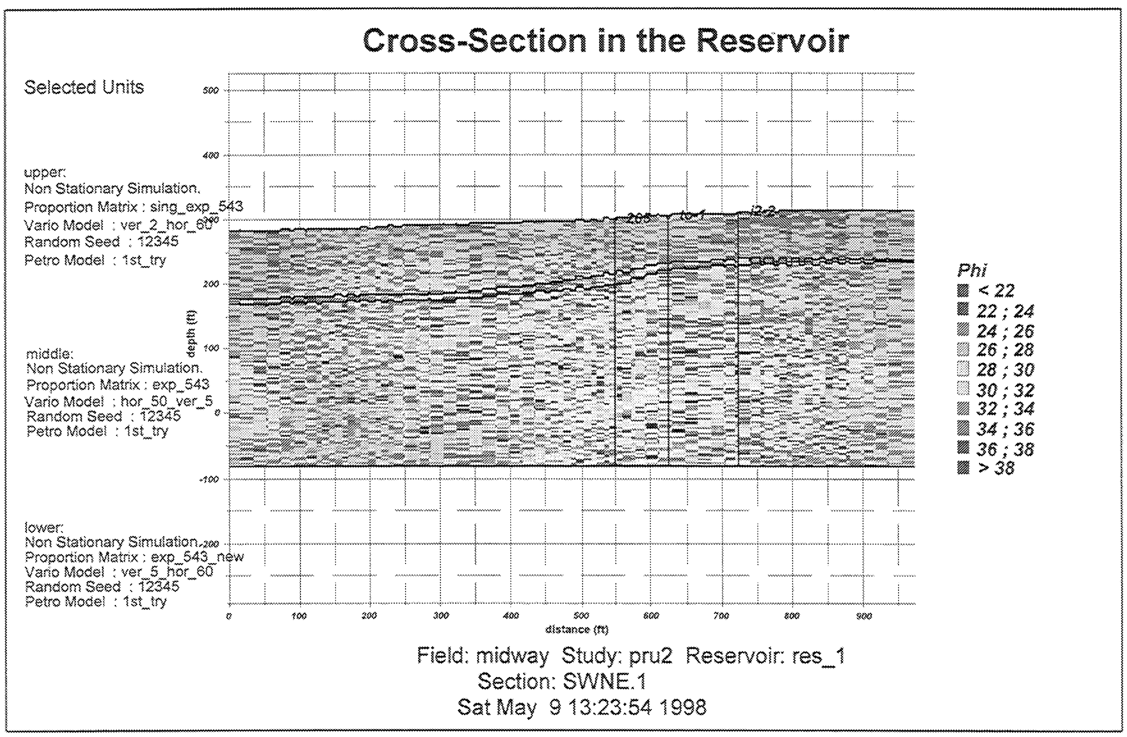


Figure 4-13. Vertical cross-sections showing computed porosity within a) northwest-southeast section, and b) southwest-northeast section. Cross-section locations are shown in Figure 4-1.

Chapter 5

Reservoir Simulation

General Statement

While waiting for the stochastic modeling of the Monarch Sand to be completed, Dr. Milind Deo continued testing alternative production strategies for the Pru steamflood demonstration using the simulator developed for the initial phase of the project. In this exercise the effects of reducing the offset of injectors and use of a horizontal producer at some future time was examined. The results of these tests, which will be repeated with the new simulator developed from the revised stratigraphic and stochastic model, are presented here.

Review of Previous Results and Motivation for Current Work

Reservoir simulation studies performed in the first phase of the project revealed that the production is dictated by the initial saturation profile. The presence of bottom water in the reservoir and associated large oil-water transition zone was the most important factor affecting oil recovery. In order to minimize heat losses in the transition zone, the conventional well completion practice (completing injectors in the bottom third of the reservoir and producers over the entire pay zone) was modified. The new completion strategy addressed only the injectors and involved lifting the injection string a certain height above the water-oil contact. Significant improvements in production performance (in flow simulations) were observed when this strategy was implemented. The predicted production performance with the use of five different production strategies is presented in Table 5-1. These results had been reported earlier and have been reproduced here for completeness. When the bottom of the injection string was lifted about 75-100 feet above the water-oil contact, an optimum oil recovery of about 25% of OOIP was observed.

Table 5-1: Comparison of production performance with the implementation of different completion strategies for the injection well.

Injector Completion (feet above WOC)	Recovery (% OOIP)	Cumulative Oil Steam Ratio	Cumulative Water Oil Ratio
136	23.1	0.12	9.6
92	25.2	0.13	9.3
76	25.2	0.13	9.4
51	21.7	0.11	11.3
30	19.0	0.095	13.5

Even with improved completion strategies, only 25% of the original oil in place was produced. The cumulative oil steam ratio of 0.13 may only be marginally economical. Hence, an exploratory study was undertaken to see if the production performance could be improved by other means. It was observed from the visualization of saturation distributions in the reservoir prior to and post steam floods that a considerable amount of oil drained down to the bottom of the reservoir and was essentially unproducible. It was hypothesized that if means of recovering this oil are found, the overall process performance would improve. New simulations were performed to see how this could be accomplished. The strategy would be to flood more of the bottom portions of the reservoir later in the life of the flood by progressively moving the injector completion downward, toward the water-oil contact.

Current Simulations and Significant Results

All the simulations were performed on a quarter symmetry element of two-acre, inverse nine-spot pattern with the well PRU 101 in the northwest corner (Figure 1-1). The cyclic-flood, parameters for which were described previously was simulated for a duration of 10 years. A total of four different scenarios were simulated.

1. Completing the wells 136 feet above the water oil contact (WOC) for the first three years; operating the flood with wells completed 92 feet above the WOC over the following three years; and, moving the completions down to 30 feet above WOC over the last four years of the flood.
2. Completing the wells 92 feet above WOC in the first eight years and operating with the wells down to 30 feet above WOC in the last two years.
3. Completing the wells 92 feet above WOC in the first eight years followed by operation at WOC of 51 feet in the last two years.
4. Completing the wells 92 feet above WOC in the first eight years and introducing a horizontal producer that is 51 feet above the WOC in the final two years.

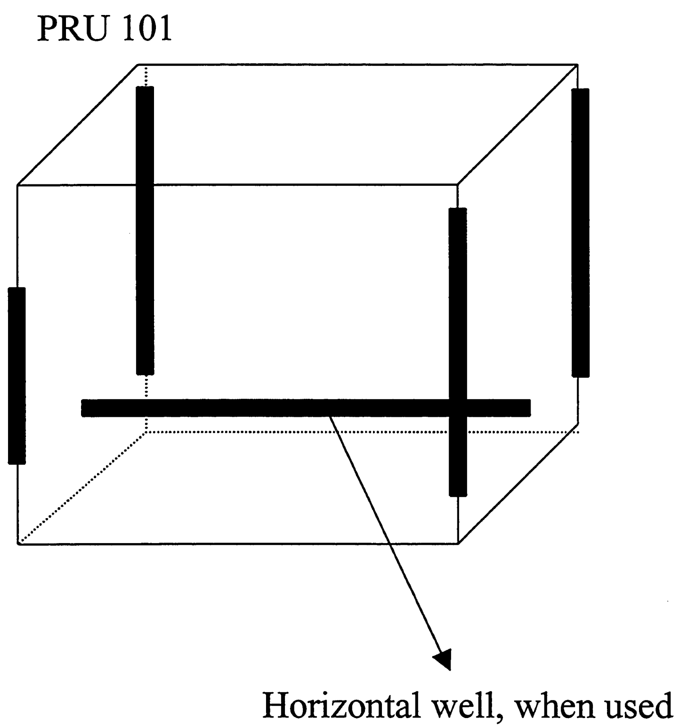


Figure 5-1 – Schematic of the symmetry element simulated

The production performance of the four scenarios is summarized below in Table 5-2.

Table 5-2: Comparison of production performance of the four scenarios simulated

Scenario Number	Recovery (%OOIP)	OSR	WOR
1	22.4	0.12	10.9
2	24.5	0.13	10.0
3	25.0	0.13	9.5
4	28.5	0.15	8.2

When compared with the best recoveries in Table 5-1, it is clear that scenario number three is marginally better, while scenario number four is significantly better. Figure 5-2 shows a comparison of cumulative oil production for scenarios 3 and 4 with base case (optimum single completion – injector 92 feet above WOC). The OSR also improves considerably (Figure 5-3). This increase is mirrored by the oil rate since the steam injection rate is essentially the same for the three cases. Once the horizontal well is introduced, significant amount of additional oil is produced. A more optimum time to drill the horizontal well may be found in simulations currently underway (for instance, introducing the horizontal well after 6 or 7 years of operation may prove more beneficial). Thus, this exercise revealed that it may be feasible to produce the oil that accumulates at the bottom of the reservoir.

Conclusions

When injectors in the pattern are completed an optimum height above the WOC oil accumulates in the bottom portion of the reservoir. When several timed-completion strategies, wherein, injector strings were lowered toward the WOC as the flood progressed were attempted, it was discovered that there is only marginal improvement in the best of cases. The only feasible way (possibly economical) of recovering the oil would be to introduce a horizontal well in the later stages of the flood. It would be possible to optimize the time of introduction of the horizontal producer and its location.

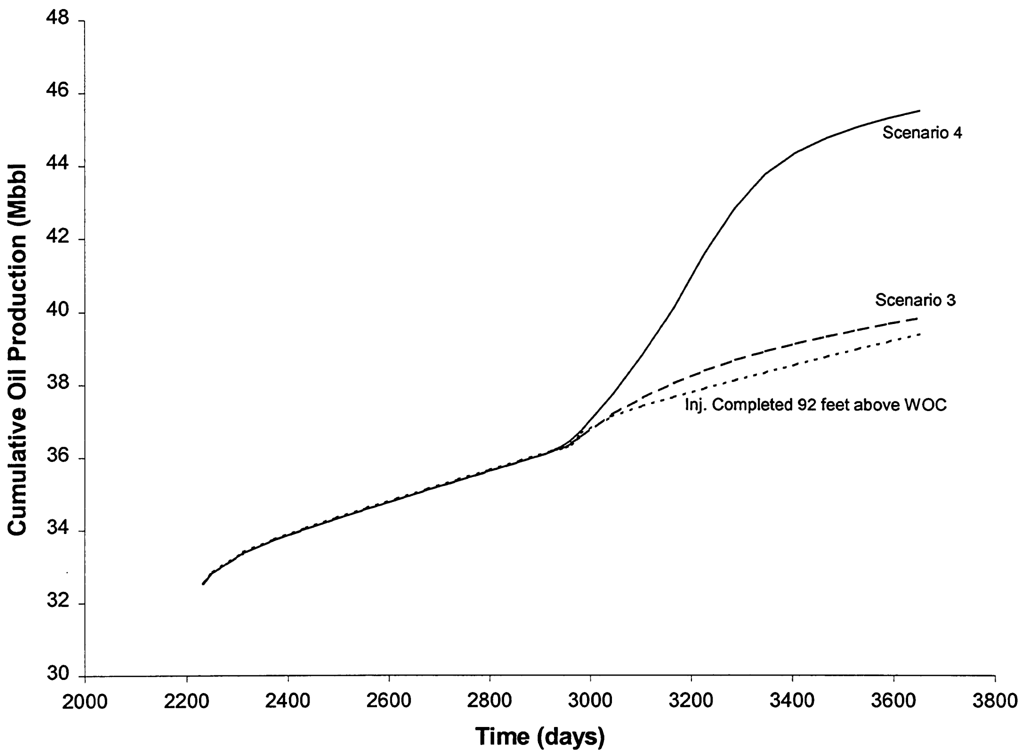


Figure 5-2: Comparison of cumulative oil production for scenarios 3 and 4 (timed completions) with the case where the injector is completed 92 feet above WOC and not altered over the life of the project.

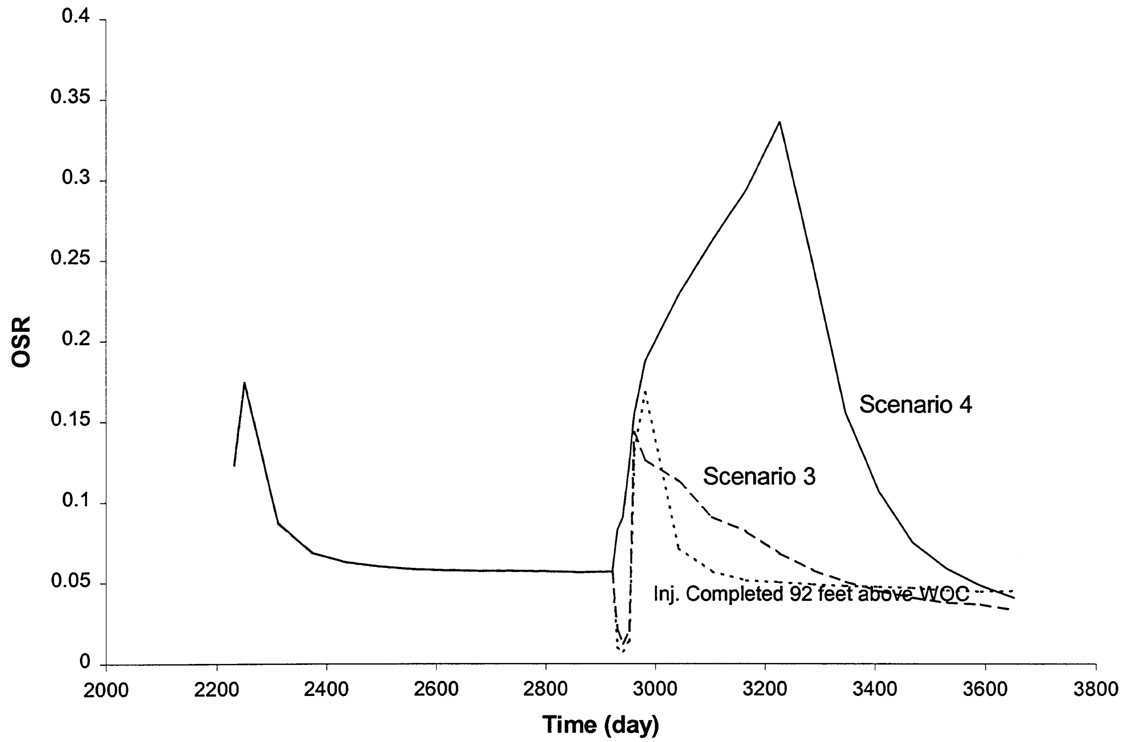


Figure 5-3- Comparison of the OSR (oil-steam ratios) curves for Scenarios 3 and 4 and for the case where the injector is completed 92 feet above the WOC and not altered over the length of the project.

Chapter 6

Technology Transfer

The DOE Class 3 oil demonstration at the Midway-Sunset Field was described in an oral presentation held in conjunction with the DOE Bi-annual Contractors Conference in Houston, Texas on June 16-20, 1997.

The paper "***Optimization of heavy-oil production by steamflood from a shallow sandstone reservoir, Midway-Sunset Field, southern San Joaquin Basin, California***" was presented at the 1998 Annual AAPG Convention (Salt Lake City) on May 19, 1998 in the poster session AAPG: Improved Recovery from Mature Oil and Gas Fields: Case Studies from DOE-sponsored Research. The authors of the paper are S. Schamel, C. Forster, M. Deo, D. Sprinkel, K. Olsen, M. Simmons, and C. Jenkins. This paper was also presented by invitation at the AAPG Pacific Region Convention, Bakersfield, California, on May 12, 1998.

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